INFORMATION SHEET

PRESIDING: Commissioner Clodfelter, Presiding; Chair Mitchell; and Commissioners Brown-Bland, Gray, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Tuesday, September 29, 2020
TIME: 9:00 a.m. – 12:30 p.m.
DOCKET NOS.: E-2, Sub 1219 and E-2, Sub 1193
COMPANY: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC
DESCRIPTION: E-2, Sub 1219, In the Matter of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-2, Sub 1193, Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 11

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

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COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
**CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED**: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Schauer, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, Luhr and Coxton

| | |
|---|---|
| REPORTED BY: Kim Mitchell | TRANSCRIPT PAGES: 183 |
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PLACE: Held via Videoconference

DATE: Tuesday, September 29, 2020

TIME: 9:00 a.m. - 12:30 p.m.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

and

DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 11

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FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER THAT AFFECTS THE PUBLIC INTEREST:

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T A B L E   O F   C O N T E N T S

E X A M I N A T I O N S

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd



E X H I B I T S

E X H I B I T S (Cont'd.)

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Commissioner Lyons Gray
Commissioner Kimberly W. Duffley
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Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina

and

DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 11

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd

E X H I B I T S (Cont'd.)

**Duke Energy Progress, LLC**
**Balance Sheet**
**As of December 31, 2018**



| Line No. | | Amount |
|---|---|---|
| | **ASSETS** | |
| | **UTILITY PLANT** | |
| 1 | Utility Plant (101-106,114) | $ 29,287,780,541 |
| 2 | Construction Work in Progress (107) | 1,665,669,162 |
| 3 | Total Utility Plant | 30,953,449,703 |
| 4 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 12,297,905,722 |
| 5 | Net Utility Plant | 18,655,543,981 |
| 6 | Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab (120.1) | 325,126,686 |
| 7 | Nuclear Materials and Assemblies - Stock Account (120.2) | 0 |
| 8 | Nuclear Fuel Assemblies in Reactor (120.3) | 819,511,288 |
| 9 | Spent Nuclear Fuel (120.4) | 417,494,987 |
| 10 | (Less) Accum. Provision for Amort. of Nuclear Fuel Assemblies (120.5) | 860,218,709 |
| 11 | Net Nuclear Fuel | 701,914,252 |
| 12 | Total Utility Plant, Net | 19,357,458,233 |
| 13 | Utility Plant Adjustments (116) | 0 |
| | **OTHER PROPERTY & INVESTMENTS** | |
| 14 | Non Utility Property (121) | 37,914,817 |
| 15 | (Less) Accum. Prov. for Depr. and Amort. (122) | 16,451,815 |
| 16 | Investment in Subsidiary Companies (123.1) | 27,726,543 |
| 17 | Other Investments (124) | 42,286,541 |
| 18 | Other Special Funds (128) | 2,776,861,603 |
| 19 | Long Term Portion of Derivative Assets - Hedges (176) | 449,408 |
| 20 | Total Other Property and Investments | 2,868,787,097 |
| | **CURRENT AND ACCRUED ASSETS** | |
| 21 | Cash (131) | (2,531,695) |
| 22 | Working Funds (135) | 0 |
| 23 | Customer Accounts Receivable (142) | 432,169,365 |
| 24 | Other Accounts Receivable (143) | 68,114,949 |
| 25 | (Less) Accum. Prov. for Uncollectible Account - Credit (144) | 7,357,981 |
| 26 | Accounts Receivable from Associated Companies (146) | 110,020,232 |
| 27 | Fuel Stock (151) | 220,024,307 |
| 28 | Plant Material and Operating Supplies (154) | 700,609,217 |
| 29 | Other Materials and Supplies (156) | 182,270 |
| 30 | Allowances (158.1 and 158.2) | 122,682,758 |
| 31 | Store Expenses Undistributed (163) | 33,384,627 |
| 32 | Prepayments (165) | 90,940,901 |
| 33 | Rents Receivable (172) | 94,136 |
| 34 | Accrued Utility Revenue (173) | 129,690,282 |
| 35 | Miscellaneous Current and Accrued Assets (174) | 10,148,021 |
| 36 | Derivative Instrument Assets Hedges (176) | 761,715 |
| 37 | (Less) Long Term Portion of Derivative Instruments Assets - Hedges | 449,408 |
| 38 | Total Current and Accrued Assets | 1,908,483,696 |
| | **DEFERRED DEBITS** | |
| 39 | Unamortized Debt Expenses (181) | 43,142,470 |
| 40 | Unrecovered Plant and Regulatory Study Costs (182.2) | 153,655,703 |
| 41 | Other Regulatory Assets (182.3) | 4,265,025,648 |
| 42 | Preliminary Survey and Investigation Charges (183) | 8,201,316 |
| 43 | Clearing Accounts (184) | 6,938,847 |
| 44 | Miscellaneous Deferred Debits (186) | 544,504,452 |
| 45 | Unamortized Loss on Reacquired Debt (189) | 4,579,195 |
| 46 | Accumulated Deferred Income Taxes (190) | 1,864,956,280 |
| 47 | Total Deferred Debits | 6,891,003,911 |
| 48 | **Total Assets** | **$ 31,025,732,937** |

**Duke Energy Progress, LLC**
**Balance Sheet**
**As of December 31, 2018**



| Line No. | | Amount |
|---|---|---|
| | **CAPITALIZATION AND LIABILITIES** | |
| | **PROPRIETARY CAPITAL** | |
| 1 | Other Paid In Capital (208-211) | $ 2,784,376,572 |
| 2 | Retained Earnings (215, 215.1, 216) | 5,933,703,999 |
| 3 | Unappropriated Undistributed Subsidiary Earnings (216.1) | (277,197,059) |
| 4 | Accumulated Other Comprehensive Income (219) | (149,270) |
| 5 | Total Proprietary Capital | 8,440,734,242 |
| | **LONG-TERM DEBT** | |
| 6 | Bonds (221) | 7,623,485,000 |
| 7 | Advances from Associated Companies (223) | 150,000,000 |
| 8 | Other Long Term Debt (224) | 350,000,000 |
| 9 | (Less) Unamortized Discount on LT Debt (226) | 15,293,974 |
| 10 | Total Long Term Debt | 8,108,191,026 |
| | **OTHER NONCURRENT LIABILITIES** | |
| 11 | Obligations Under Capital Leases (227) | 133,281,241 |
| 12 | Accumulated Provision for Property Insurance (228.1) | 0 |
| 13 | Accumulated Provision for Injuries and Damages (228.2) | 6,874,145 |
| 14 | Accumulated Provision for Pensions and Benefits (228.3) | 223,622,886 |
| 15 | Accumulated Miscellaneous Operating Provisions (228.4) | 17,201,995 |
| 16 | Accumulated Provision for Rate Refund (229) | 123,351,482 |
| 17 | LT Portion of Derivative Instrument Liabilities | 4,886,654 |
| 18 | LT Portion of Derivative Instrument Liabilities - Hedges | 3,728,239 |
| 19 | Asset Retirement Obligations (230) | 4,819,759,728 |
| 20 | Total Other Noncurrent Liabilities | 5,332,706,370 |
| | **CURRENT AND ACCRUED LIABILITIES** | |
| 21 | Accounts Payable (232) | 723,822,837 |
| 22 | Notes Payable to Associated Companies (233) | 293,651,000 |
| 23 | Accounts Payable to Associated Companies (234) | 271,157,048 |
| 24 | Customer Deposits (235) | 137,270,708 |
| 25 | Consolidated Taxes Accrued (236) | 59,278,673 |
| 26 | Interest Accrued (237) | 116,877,826 |
| 27 | Tax Collections Payable (241) | 7,936,232 |
| 28 | Miscellaneous Current and Accrued Liabilities (242) | 227,936,822 |
| 29 | Obligations Under Capital Leases - Current (243) | 3,267,405 |
| 30 | Derivative Instrument Liabilities (244) | 16,120,103 |
| 31 | (Less) LT Portion of Derivative Instrument Liabilities | 4,886,654 |
| 32 | Derivative Instrument Liabilities - Hedges (245) | 6,466,582 |
| 33 | (Less) LT Portion of Derivative Instrument Liabilities - Hedges | 3,728,239 |
| 34 | Total Current and Accrued Liabilities | 1,855,170,343 |
| | **DEFFERED CREDITS** | |
| 35 | Customer Advances for Construction (252) | 22,775,276 |
| 35 | Accumulated Deferred Investment Tax Credits (255) | 142,161,990 |
| 36 | Other Deferred Credits (253) | 19,844,812 |
| 37 | Other Regulatory Liabilities (254) | 3,120,844,123 |
| 38 | Accumulated Deferred Income Taxes Oth Property (282) | 2,695,677,136 |
| 39 | Accum Deferred Income Tax Other (283) | 1,287,627,619 |
| 40 | Total Deferred Credits | 7,288,930,956 |
| 41 | **Total Capitalization and Liabilities** | **$ 31,025,732,937** |

**Duke Energy Progress, LLC**
**Income Statement**
**For The Test Period (12 Months) Ended December 31, 2018**

**Angers Exhibit 1**
**Docket No. E-2, Sub 1219**


| Line No. | | Amount |
|---|---|---|
| 1 | **Operating Revenues (400)** | $ 5,682,421,296 |
| | **Operating Expenses** | |
| 2 | Operation Expenses (401) | 2,842,529,953 |
| 3 | Maintenance Expenses (402) | 524,022,724 |
| 4 | Depreciation Expenses (403) | 746,423,281 |
| 5 | Amortization and Depletion of Utility Plant (404-405) | 42,090,299 |
| 6 | Amortization of Utility Plant Acq. Adj. (406) | 12,758,733 |
| 7 | Amortization of Prop Loss, Unrecov Plant and Reg Study Cost (407) | 29,040,562 |
| 8 | Regulatory Debits (407.3) | 365,010,904 |
| 9 | (Less) Regulatory Credits (407.4) | 135,488,252 |
| 10 | (Less) Gains from Disposition of Allowances (411.8) | 165,404 |
| 11 | Total Depreciation and Amortization Expenses | 1,059,670,123 |
| 12 | Taxes Other Than Income Taxes (408.1) | 153,362,211 |
| 13 | Total Operating Expense Before Income Taxes | 4,579,585,011 |
| 14 | Income Taxes - Federal (409.1) | (66,292,964) |
| 15 | Income Taxes - Other (409.1) | (3,938,471) |
| 16 | Provision for Deferred Income Taxes (410.1) | 834,871,407 |
| 17 | (Less) Provision for Deferred Income Tax Credit (411.1) | 614,018,430 |
| 18 | Investment Tax Credit Adjustment Net (411.4) | (3,355,660) |
| 19 | Total Income Taxes On Operating Income | 147,265,882 |
| 20 | **Total Utility Operating Expenses** | **4,726,850,893** |
| 21 | **Net Utility Operating Income** | **955,570,403** |
| | **Other Income** | |
| 22 | Revenues from Merchandising, Jobbing and Contract Work (415) | (86,843) |
| 23 | (Less) Costs and Exp. of Merchandising, Job & Contract Work (416) | 29,121 |
| 24 | Revenues from Nonutility Operations (417) | 33,624,375 |
| 25 | (Less) Expenses of Nonutility Operations (417.1) | 23,752,601 |
| 26 | Non Operating Rental Income (418) | (633,026) |
| 27 | Equity in Earnings of Subsidiary Companies (418.1) | 7,394,428 |
| 28 | Interest and Dividend Income (419) | 1,387,385 |
| 29 | Allowance for Other Funds Under Construction (419.1) | 56,812,523 |
| 30 | Miscellaneous Nonoperating Income (421) | 9,121,726 |
| 31 | Gain On Disposal Of Property (421.1) | 1,296,268 |
| 32 | Total Other Income | 85,135,114 |
| | **Other Income Deductions** | |
| 33 | Loss on Disposition of Property (421.2) | 383,831 |
| 34 | Miscellaneous Amortization (425) | - |
| 35 | Donations (426.1) | 3,334,051 |
| 36 | Life Insurance (426.2) | (1,642,235) |
| 37 | Penalties (426.3) | 1,878,534 |
| 38 | Exp. For Certain Civic, Political and Related Activity (426.4) | 3,159,976 |
| 39 | Other Deductions (426.5) | 34,603,501 |
| 40 | Total Other Income Deductions | 41,717,658 |
| | **Taxes Applicable to Other Income and Deductions** | |
| 41 | Taxes Other than Income Taxes (408.2) | 1,961,060 |
| 42 | Income Taxes - Federal (409.2) | (5,144,014) |
| 43 | Income Taxes - Other (409.2) | (645,223) |
| 44 | Provision for Deferred Income Taxes (410.2) | 28,378,574 |
| 45 | (Less) Provision for Deferred Income Taxes - Cr (411.2) | 9,796,689 |
| 46 | Total Taxes on Other Income and Deductions | 14,753,708 |
| 47 | **Net Other Income and Deductions** | **28,663,748** |
| | **Interest Charges** | |
| 48 | Total Interest on Long - Term Debt (427) | 316,675,114 |
| 49 | Amortization of Debt Discount and Exp (428) | 5,814,338 |
| 50 | Amortization of Loss on Reacquired Debt (428.1) | 1,030,335 |
| 51 | Interest on Debt to Associated Companies (430) | 8,649,424 |
| 52 | Other Interest Expense (431) | 10,728,365 |
| 53 | (Less) Allowance for Borrowed Funds Used During Construction - Cr (432) | 25,699,616 |
| 54 | Net Interest Charges | 317,197,960 |
| | **Income Before Extraordinary Items** | **667,036,191** |
| | **Extraordinary Items** | |
| | Extraordinary Deductions (435) | - |
| | Net Extraordinary Items | - |
| | Income Taxes Federal and Other (409.3) | - |
| | Extraordinary Items After Taxes | - |
| 55 | **Net Income** | **$ 667,036,191** |

**Duke Energy Progress, LLC**
**Statement of Capitalization**
**As of December 31, 2018**



**Long-Term Debt**

| Line Number | Description | Rate | Interest Type | Maturity Date | | Outstanding Balance | Percent of Total |
|---|---|---|---|---|---|---|---|
| 1 | Intercompany borrowings (Money pool) | 2.794% | Floating | 03/16/23 | $ | 150,000,000 | |
| 2 | First Mortgage Bond | 8.625% | Fixed | 09/15/21 | | 100,000,000 | |
| 3 | First Mortgage Bond | 6.125% | Fixed | 09/15/33 | | 200,000,000 | |
| 4 | First Mortgage Bond | 5.700% | Fixed | 04/01/35 | | 200,000,000 | |
| 5 | First Mortgage Bond | 6.300% | Fixed | 04/01/38 | | 325,000,000 | |
| 6 | First Mortgage Bond | 3.000% | Fixed | 09/15/21 | | 500,000,000 | |
| 7 | First Mortgage Bond | 2.800% | Fixed | 05/15/22 | | 500,000,000 | |
| 8 | First Mortgage Bond | 4.100% | Fixed | 05/15/42 | | 500,000,000 | |
| 9 | First Mortgage Bond | 4.100% | Fixed | 03/15/43 | | 500,000,000 | |
| 10 | First Mortgage Bond | 4.375% | Fixed | 03/30/44 | | 400,000,000 | |
| 11 | First Mortgage Bond | 4.150% | Fixed | 12/01/44 | | 500,000,000 | |
| 12 | First Mortgage Bond | 3.250% | Fixed | 08/15/25 | | 500,000,000 | |
| 13 | First Mortgage Bond | 4.200% | Fixed | 08/15/45 | | 700,000,000 | |
| 14 | First Mortgage Bond | 3.700% | Fixed | 10/15/46 | | 450,000,000 | |
| 15 | First Mortgage Bond | 2.947% | Floating | 09/08/20 | | 300,000,000 | |
| 16 | First Mortgage Bond | 3.600% | Fixed | 09/15/47 | | 500,000,000 | |
| 17 | First Mortgage Bond | 3.375% | Fixed | 09/01/23 | | 300,000,000 | |
| 18 | First Mortgage Bond | 3.700% | Fixed | 09/01/28 | | 500,000,000 | |
| 19 | Tax-Exempt Bonds | 4.000% | Fixed | 06/01/41 | | 48,485,000 | |
| 20 | Secured Debt (DEPR)* | 3.335% | Floating | 02/22/21 | | 180,000,000 | |
| 21 | Secured Debt (DEPR)* | 3.514% | Floating | 02/22/21 | | 120,000,000 | |
| 22 | Unsecured Debt | 3.040% | Floating | 12/31/20 | | 50,000,000 | |
| 23 | Unamortized Debt (Discount)/Premium | | | | | (15,291,810) | |
| 24 | **Total Long Term Debt** | | | | **$** | **7,508,193,190** | **46.3%** |

**Regulatory Common Equity**

| Line Number | Description | | Balance | Percent of Total |
|---|---|---|---|---|
| 25 | Other Paid in Capital | $ | 2,784,376,572 | |
| 26 | Retained Earnings | | 6,210,751,788 | |
| 27 | Accumulated Other Comprehensive Income | | (149,270) | |
| 28 | Unappropriated Undistributed Subsidiary Earnings | | (277,197,059) | |
| 29 | **Total Common Equity** | **$** | **8,717,931,301** | **53.7%** |
| 30 | **Total Regulatory Capitalization** | **$** | **16,226,124,491** | **100.0%** |

*DEPR - Duke Energy Progress Receivables, LLC

**Duke Energy Progress, LLC**
**Docket No. E-2, Sub 1219**
**Cash Working Capital for NC Retail Operations - Lead Lag Summary**
**For the test period ended December 31, 2018**
**Summer CP Demand Allocation with MINIMUM SYSTEM**

| Line No. | Description | NC Retail Jurisdictional Amount [A] | Lead \Lag Days [B] | Weighted Amount [C] |
|---|---|---|---|---|
| | **Calculation of NC Retail Amount:** | | | |
| 1 | Total Revenue Lag | (3,657,503,448) | 42.13 | (154,105,864,564) |
| 2 | Operation and Maintenance Expense | 2,091,224,112 | 32.27 | 67,473,737,467 |
| 3 | Depreciation and Amortization | 669,787,484 | 0.00 | 0 |
| 4 | Taxes Other Than Income Taxes | 102,197,044 | 123.16 | 12,586,614,755 |
| 5 | Interest on Customer Deposits | 7,970,989 | 137.50 | 1,096,011,021 |
| 6 | Income Taxes | 112,986,202 | (20.60) | (2,327,336,581) |
| 7 | Investment of Tax Credit | (2,133,914) | 0.00 | 0 |
| 8 | Net Operating Income | 675,471,531 | 27.48 | 18,562,553,881 |
| 9 | Total Requirements (Sum L3 through L9) | 3,657,503,448 | 26.63 | 97,391,580,542 |
| 10 | Revenue Lag Days (L1) | | 42.13 | |
| 11 | Requirement Lead Days (L9) | | 26.63 | |
| 12 | Net Lag Days (L10 + L11) | | 15.51 | |
| 13 | Daily Requirements (Line 9, Column A divided by 365) | | | 10,020,557 |
| 14 | Cash Working Capital Requirements (L12 x L13) | | | 155,381,600 |
| 15 | Add: Cash Working Capital Related to NC Sales Tax | | | 4,759,823 |
| 16 | Total Cash Working Capital Requirements for NC Retail | | | 160,141,423 |
| 17 | **Calculation of Total Company and Jurisdictional Amounts:** | | | |
| 18 | NC Retail: Cash Working Capital allocated at NB_PLT Factor | | | 67.0949% |
| 19 | Total Company Cash Working Capital Requirements (L16 / L18) | | | 238,679,065 |
| 20 | NC Retail Factor | | | 67.0949% |
| 21 | SC Retail Factor | | | 10.0953% |
| 22 | Total Wholesale Factor | | | 22.8098% |
| 23 | Total (Sum L20 through L22) | | | 100.0000% |
| 24 | NC Retail Cash Working Capital Requirement (L19 x L20) | | | 160,141,423 |
| 25 | SC Retail Cash Working Capital Requirement (L19 x L21) | | | 24,095,385 |
| 26 | Total Wholesale Cash Working Capital Requirement (L19 x L22) | | | 54,442,257 |
| 27 | Total Company Cash Working Capital Requirement (Sum L24 through L26) | | | 238,679,065 |

# Duke Energy Progress, LLC

## Lead Lag Study

## July 2019

Building a better working world

Building a better working world

Ernst & Young LLP
100 N Tryon St
Charlotte, NC 28202

Tel: +1 704 372 6300
ey.com

July 22, 2019

Abbe Greenfield
Rate Case Planning & Execution, Duke Energy Progress, LLC
526 South Church Street
Charlotte, NC 28202

Mrs. Greenfield:

We have completed our procedures with respect to analyzing a detailed lead lag study for Duke Energy Progress, LLC ("the Company" or "DEP") focused on retail operations in the state of North Carolina. Our procedures were performed in accordance with our Statement of Work, dated April 19, 2018. Our report consists of three parts. We summarize our scope, approach, and findings in a narrative executive summary. We present our detailed findings in a schedule that provides the lag and lead days by revenue and expense component used by DEP in its cost of service filings; and we include an appendix that provides the Company's summary calculations.

The information provided in this report is intended to be used to support the Company's request for a Cash Working Capital allowance to be included in the Company's requested rate base to be authorized by the North Carolina Utility Commission. The report is not intended to be, and should not be, used without our prior written consent by any other party or for any other purpose. Our calculations relied on underlying accounting information provided by the Company. We did not audit that underlying accounting information.

We value the opportunity to work with you and appreciate the cooperation and assistance provided. We would be pleased to discuss any aspect of our work or this report with you or other members of management at your convenience. If you have questions, please call Jake Van Reen at (617) 375-2446.

Thank you,

Jake Van Reen

# Table of Contents

# Executive Summary

## 1.1. Organization of Report

This report is composed of three parts: Executive Summary, Detailed Findings, and Appendix.

The Executive Summary provides background on the engagement, the purpose and scope of the lead lag study, the standards applied and the relation to previous studies, and a discussion of key findings.

The Detailed Findings are provided in a DEP Lead Lag Summary schedule contained within E-1 Item 14. This schedule provides the lag and lead days by revenue and expense component used by the Company in its cost of service filings. The summary was agreed to the underlying supporting schedules.

## 1.2. Background

Duke Energy ("Duke") engaged Ernst & Young ("EY") to support the preparation of a lead lag study for Duke's retail operations in the state of North Carolina. The study will be used to support the Company's request for a Cash Working Capital allowance to be included in the requested rate base. This report presents the methodology and approach used in the study and the results covering the twelve-month period ending December 31, 2017, subject to known changes.

The Company last presented a lead lag study to the North Carolina Utility Commission ("NCUC" or the "Commission") for the twelve-month period ending December 31, 2010. This report presents the lead lag study in the same general format and applies the same methodologies where applicable. Since that time, there are assumed to have been no significant changes in the operating and regulatory environments that would materially affect the calculation of the Cash Working Capital requirements. To confirm this assumption, EY interviewed Duke personnel and a contractor responsible for compiling the study. EY also compared certain of the Company's financial statements and riders to DEP's regulatory requirements for the same purpose.

## 1.3. Cash Working Capital

### 1.3.1. Purpose of lead lag study

The lead lag study is designed to measure the average amount of capital, over and above the investments in plant, and other separately identified rate base items, provided by investors, to bridge the gap between the time expenditures are required to provide service and the time collections of revenues are received for the service. This quantity is referred to as Cash Working Capital. Cash Working Capital is more comprehensive than simply financing the lag between Company payments and receipts, as investor capital is required to finance the lag in the recovery of the entire cost of service, including depreciation and cost of capital.

### 1.3.2. Cash Working Capital requirement

A requirement for Cash Working Capital represents the amount necessary to provide the utility with an opportunity to appropriately earn an authorized return on all capital invested in utility operations. Unless all capital supplied by investors has that opportunity, investors will not be fully compensated for the capital supplied and the objective of the Cash Working Capital requirement will not be met. Consequently, the key test of the adequacy of the Cash Working Capital requirement should be whether the inclusion of such an amount, when added to net utility plant and other items includible in the rate base, will produce a fair representation of the capital on which there should be an opportunity to earn a return.

### 1.3.3. Lead lag study methodology

To the extent applicable, this study tracks the methodology used in the previous rate filings of the Company and decisions of the NCUC.

The lead lag study measures the difference in time frames between: (1) when service is rendered and the revenue for that service is received ("revenue lag"); and (2) when the costs of providing service are incurred (including costs of fuel and purchased power, labor, materials, services, etc.) and the time for which those costs are paid ("expense lead"). The difference between these lag periods is expressed in terms of days. The calculated number of days, multiplied by the average daily operating revenues or cost of service, produces the Cash Working Capital required by the Company.

To fully identify Cash Working Capital requirements, there are additions and deductions to the amount calculated in the lead lag study. This is done to adjust for items not accounted for in rate base. For example, we must add operational cash requirements and add or deduct any other requirements for, or sources of, Cash Working Capital (such as prepayments, reserves, and items capitalized prior to payment). In previous rate case proceedings, these adjustments have been considered separately from the lead lag study, so they are not considered in this report.

#### 1.3.4. Results of lead lag study for DEP retail electric operations

The following section provides a summary of the most significant revenue lags and expense leads calculated. Additional detailed identification of the calculated revenue lags and expense leads is included in the attached schedule entitled E-1 Item 14 ("the summary schedule").

### 1.4. Revenue Lag

The revenue lag measures the time between service delivery to customers and the collection of revenue for service from customers. For the year ending December 31, 2017, the majority of North Carolina retail jurisdictional revenue was received from cycle billed customers (customers billed on a periodic basis) and the large customer billing groups.

The revenue lag for these services is the sum of three components: (i) service lag, (ii) billing lag and (iii) collection lag.

The first component is service lag. The Company reads the meters on a monthly basis; therefore the average time between meter reads is 30.42 days (365 days in a year divided by 12 monthly meter reads). Dividing by two provides the midpoint in time, or the average time between when service is provided and the meter read, for a service lag of 15.21 days. (See summary schedule line 4.)

The second component of the total revenue lag is billing lag, the time from the meter reading to when the customer is billed and the bill is posted in the Company's accounts receivable system. Most customers are billed the next business day after the meter reading. Taking into account weekends and holidays, the calculation of the total billing lag is 1.66 days. (See summary schedule line 6.) This amount differs from the previous study, which deemed the billing lag to be at approximately half a day, as the previous study did not account for weekends and holidays.

The third component of the total revenue lag is the collection lag, the period from the billing date to the time the customer pays their bill (i.e., the date cash payments are credited on the accounts receivable records). This component of the revenue lag is measured by dividing average daily accounts receivable (based on a thirteen-month average) by average daily sales. Collection policies for retail operations in North Carolina are governed by NCUC rules. We calculated the collection lag to be 25.01 days. (See summary schedule line 10.)

Adding these three components together produced a total lag of 41.88 days in the collection of revenues for services provided to cycle-read and large customer billing group customers on electric delivery rate schedules. (See summary schedule line 12.)

EY did not factor in the potential impact of float. The Company experiences two float periods - the time from when funds are received from customers until the funds clear the banks, and the time between when the Company sends a check to pay for services and when those checks are deposited. In the first instance, the Company's cash requirements are increased by the float (i.e. funds are not actually available until after the deposits clear). However, in the second instance, the Company's cash requirements are reduced by the float. Given the relative levels of electronic funds transfers in the Company's payments versus in its receipts, we are confident that the float for revenue is larger than the float for expense. Accordingly, excluding float in this instance is a conservative assumption that would not harm the ratepayer.

In addition to the above, the Company records a variety of additional and miscellaneous revenues which are also applicable to the North Carolina retail jurisdiction. These include intersystem sales for resale, forfeited discounts, rental income, and other electric revenue. To calculate the overall average revenue lag, we calculated the revenue lags for each of the additional and miscellaneous revenues. The total revenue lag for DEP is 42.33 days. (See summary schedule line 38.)

### 1.5. Expense lead

There are several major categories of expense including:

- O&M Fuel

- O&M Purchased Power
- Other Specifically Identified O&M
- Other O&M Sampled
- Depreciation and Amortization
- Taxes other than Income
- Interest on Customer Deposits
- Income Taxes
- Net Operating Income
- Cash Working Capital impacts of Pass Through items

Each of the above are described in more detail below.

### 1.5.1. O&M Fuel

O&M Fuel costs consist of coal, oil, and natural gas purchases. Fuel is the largest cost category, accounting for approximately 23% of the cost of service for the year ending December 31, 2017. Coal includes two major cost components: coal commodity purchases and coal transportation costs. The cost of coal purchases and transportation are inventoried and, by NCUC precedent, coal fuel inventories are included in rate base. However, the Cash Working Capital requirement must recognize the cash available to the Company stemming from the time between receipt of coal and the subsequent payment of the fuel or transportation invoice.

DEP receives thousands of coal deliveries at its coal generating stations each year. DEP employs the following coal payment terms: (i) contract deliveries made between the 1st and 15th of the current month are paid by the 30th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days); (ii) contract deliveries made between the 1st and 15th of the current month are paid by the 25th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 10th of the following month (17.5 days); (iii) contract deliveries made between the 1st and 31st of the current month are paid by the 30th of the following month (45 days); (iv) contract deliveries made between the 1st and 15th of the current month are paid by the 10th of the following month or contract deliveries made between the 16th and 31st of the current month are paid by the 25th of the following month (32.5 days); and (v) contract deliveries paid 10 days after ship date (10 days). Vendor contracts require DEP payments to be received by the noted due date.

DEP employs the following vendor coal transportation contract terms: (i) coal freight payments 15 days after the ship date (15 days); (ii) coal freight received between the 1st and 15th of the current month are paid by the 30th of the current month or coal freight received between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days).

A small amount of oil is also used as a fuel for generation. Natural gas made up a large portion of the generation fuel. Unlike coal or oil, natural gas is not stored and inventoried, rather it is purchased as it is used to generate electricity. Therefore, the expense lag for natural gas is computed conventionally as the difference between the service period and the date of payment. Since Duke is not storing natural gas to be used for generation, the service period is considered to be the mid-point of the billing period from the gas supplier, and the payment date is simply the date of payment.

The O&M Fuel expense lead for coal, oil and natural gas is 28.62 days. (See summary schedule line 44.)

### 1.5.2. O&M Purchased Power

DEP provided a listing of all transactions for each Purchased Power account. We weighted the individual invoices by dollar amount, resulting in an overall expense lead of 68.18 days. (See summary schedule line 51.)

### 1.5.3. Other Specifically Identified O&M

Other specifically identified O&M categories include the following accounts:

- O&M Labor and Benefits
- Uncollectible accounts
- Regulatory expenses
- Nuclear fees
- Property Insurance expenses

Labor and Benefits comprised approximately 11% of the cost of service for the year ending

December 31, 2017. Labor costs fall into three categories: net payroll, deductions from payroll, and taxes. In turn, the Company's payroll consists of two primary categories, semi-monthly payroll and bi-weekly payroll, with lesser amounts of incentive pay. We identified each pay period and the payment dates corresponding to that pay period. For payroll related deductions (income taxes, social security, etc.) we identified each deduction and when the payments for each deduction were made.

Uncollectible accounts expenses result from the timing of the write-off of customer accounts receivable as uncollectible. By NCUC practice, these expenses are valued at zero days expense lead. (See summary schedule line 57.)

We calculated expense lead days for regulatory, nuclear fees, and insurance expenses by analyzing service periods, payment amounts and payment patterns. By its nature, regulatory expense is a quarterly or annual expense and tends to have a longer lead period. For the twelve months ending December 31, 2017, the expense lead for Regulatory Commission Expense was 103.01 days. (See summary schedule line 63.) Nuclear fees have a calculated expense lead of (34.66) days. (See summary schedule line 59.)

Property Insurance expenses are payments for policies. By their nature, insurance policies are paid prior to the service period for coverage and have a negative expense lead. For the twelve months ending December 31, 2017, the expense lead for Property Insurance was (222.30) days. (See summary schedule line 65.)

### 1.5.4. Other O&M Sampled

To determine the expense lead for Other O&M not specifically analyzed (summary schedule line 69), the Company provided EY with a listing of cash disbursements for the twelve-month period ending December 31, 2017. We removed records for capital costs, non-electric O&M costs, and any costs already analyzed, resulting in a sample population consisting of $497,471,687 and 22,967 rolled vouchers. (Note: there were over 214,000 records, but multiple disbursements were made on the same voucher; since the voucher was the unit sampled, the records were rolled up to the voucher level). From that population, a stratified random sample in nine strata, based on the invoice dollar amount, was selected (260 total selections) for sample testing. For each item sampled, the supporting documentation was obtained and analyzed. For purposes of the analysis, service period information was either provided by Duke based on the supporting documentation or, in instances where the service period was not available, the invoice date was provided. The paid dates utilized in the analysis were taken from the Company's payables ledger.

The estimated weighted average expense lead calculated from the sample was 44.01 days, plus or minus 4.96 days with 90% confidence. This contrasts to the 32.65 days calculated for the Other O&M sample from the previous lead lag study. When asked about the increase in days, the client informed us that Duke has 45-day payment terms, and has been following these more closely than previously. EY used statisticians to sample the Other O&M population.

In addition, approximately 1% of the Other O&M costs are employee expenses. These were included in our sample, and we calculated the average lead lag days based on the credit card payment dates. All credit cards have the same monthly service period and payment date. As a result, these were not sampled. Rather the expense lead was calculated as the average time from the midpoint of the service period to the payment date.

### 1.5.5. Depreciation and Amortization

Expenses for Depreciation and Amortization are the result of prior cash transactions that are not initially charged to expense. A zero lag is applied because the expense is deducted from rate base when the expense is recorded. By way of example, investors supply cash for capital investments such as plant assets. A cash transaction occurs when a plant asset is acquired. The plant asset is included in rate base and the cash investment earns a return until depreciation expense is recorded. When depreciation expense is recorded, the amount of the expense is removed from rate base and the expense becomes recoverable in cost of service. However, the cash is not recovered until revenues are collected (*e.g.*, after the revenue lag). Thus, depreciation expense is included in the lead lag study with a zero expense lead to provide a return for the period from when the depreciation expense is booked and removed from rate base until it is recovered from revenues. (See summary schedule line 75.)

### 1.5.6. Taxes other than Income

Expense leads for Taxes other than Income Taxes consider the timing between tax assessments, and the related service period. Some taxes are paid after a significant portion of the service period has occurred. Overall the average expense lead for Taxes other than Income for the period ending December 31, 2017 was 120.52 days. (See summary schedule line 84.) Per the 2010 lead lag study, the average expense lead on Taxes other than Income was 62.90. The increase in the number of days is largely the result of a tax reform occurring in 2014, which had a considerable impact on Privilege or Franchise Tax. These taxes were previously paid shortly after the service period. This rapid payment had previously offset the impact of property taxes, which are paid nearly a year after the service period begins.

### 1.5.7. Interest on Customer Deposits

Interest is credited to customers who are required to maintain deposits, and the interest is paid either when the deposit is returned or at periodic intervals. The expense lead on customer deposits is 137.50 days. (See summary schedule line 86.)

### 1.5.8. Income Taxes

Income Taxes have two major components, current and deferred Income Taxes. In turn, current Income Taxes include taxes for the current year and prior periods. The expense lead for current Income Taxes is the result of the statutory payment dates. Similar to the rationale for depreciation expense, the deferred tax expense lead is zero days because net deferred tax liabilities are deducted from rate base when the expense is recorded. The expense lead on Net Income Taxes is (11.49) days. (See summary schedule line 91.)

### 1.5.9. Net Operating Income

Net Operating Income is the return on invested capital, just as depreciation expense is a return on invested capital. Like depreciation expense, a zero lag was assigned to Net Operating Income in recognition of the fact that the return is earned when the service is provided. (See summary schedule line 99.) Because the return is earned when the service is provided, it would be inappropriate to consider subsequent below the line treatment of Net Operating Income. Therefore, we did not further analyze the subsequent use of Net Operating Income for interest, dividends or reinvestment.

### 1.5.10. Cash Working Capital impacts of Pass Through items

As noted, to fully identify the Cash Working Capital requirements, to the amount calculated in the lead lag study we must add operational cash requirements and add or deduct any other requirements for or sources of Cash Working Capital. One item the Company has not included elsewhere and is therefore considered here is pass through taxes. Pass through taxes are similar to Taxes other than Income except the payment is due from customers not the Company. The primary pass through tax is the North Carolina utility sales tax. The Company collects these pass through taxes from customers in their bills and pays the tax to the State. The tax is not a Company expense because the Company is merely a conduit of the payments from customers. But, to the extent the Company pays the tax before the funds are received from customers, investors in the Company need to provide the cash to finance the time between payment and recovery. The impact on total DEP Cash Working Capital requirements due to the NC sales pass through tax is $5,841,335. (See summary schedule line 104.)

## Conclusion

We have calculated the revenue lag days and expense lead days documented in the schedule described above. We have also tested the reasonableness of the results based on both a logical review of the revenue and expense items using business operating parameters, and on a comparison to historical results. Based on our analyses, we conclude that these revenue lag days and expense lead days are reasonable and calculated properly.

## Detailed Findings

The revenue lag and expense lead calculations developed in this study are overall quite similar when compared to the 2010 calculations, indicating there have been no significant changes in the operating and regulatory environments that would materially affect the overall calculation of the Cash Working Capital requirements. The calculated overall revenue lag calculated is 42.33 days versus 38.39 days in the prior study, reflecting a reasonably stable revenue lag.

On the expense side there appears to be more variability in the calculated expense leads among individual expense line items. However, the overall expense lead of 21.92 days is consistent with the 20.68 days in the prior study.

Among individual expense items, the expense lead for Taxes other than Income was considerably different. The current study calculated this lead at 120.52 days, versus 62.90

days previously. The increase in the number of lead lag days is largely the result of a 2014 tax reform, which had a significant impact to Privilege or Franchise Tax. These had previously offset the impact of property taxes.

As previously noted, the expense lead for Other O&M not separately analyzed increased to 44.01 days, due to stricter adherence to DEP's 45-day payment terms.

The Cash Working Capital requirement is currently calculated at $187.1 million. When factoring in NC Sales Tax, this amount increases to approximately $193.0 million with rounding, representing a $16.5 million increase from the previous study. This appears to be predominantly driven by a longer revenue lag. The daily requirement decreased from the 2010 study, however the expansion of days for the revenue lag was larger than the expansion of days in the requirement lead. Additionally, pass through items increased tenfold from the previous study. Other Income Taxes had a minimizing effect by expanding the Requirement Lead Days, but the increase in revenue lag and pass through items requires a larger Cash Working Capital.

# Appendix

| Duke Energy Progress, LLC<br>Cash Working Capital Requirements for NC Retail Operations<br>Lead Lag Summary<br>For the 12 Months Ended December 31, 2017 | | | |
|---|---|---|---|
| | NC Retail Jurisdictional Amount | Lead \Lag Days | Weighted Amount |
| Total Revenue Lag | (3,347,347,114) | 42.33 | (141,692,605,927) |
| Operation and Maintenance Expense | 1,828,010,618 | 34.42 | 62,923,055,892 |
| Depreciation and Amortization | 539,354,933 | 0.00 | 0 |
| Taxes Other Than Income Taxes | 100,773,052 | 120.52 | 12,145,541,369 |
| Interest on Customer Deposits | 8,712,804 | 137.50 | 1,198,010,503 |
| Income Taxes | 250,394,479 | (11.49) | (2,876,315,948) |
| Investment of Tax Credit | (2,136,868) | 0.00 | 0 |
| Net Operating Income | 622,238,096 | 0.00 | 0 |
| **Total Requirements** | 3,347,347,114 | 21.92 | 73,390,291,817 |
| Revenue Lag Days | | 42.33 | |
| Requirement Lead Days | | 21.92 | |
| Net Lag Days | | 20.40 | |
| Daily Requirements | | | 9,170,814 |
| Cash Working Capital Requirements | | | 187,129,628 |
| Working Capital Related to NC Sales Tax | | | 5,841,335 |
| Total Cash Working Capital Requirements | | | 192,970,963 |

**Duke Energy Progress, LLC**
**Cash Working Capital Requirements for NC Retail Operations**
**Lead Lag Summary**
**For the 12 Months Ended December 31, 20177**

| Line No. | Total Utility Operating Revenue and Expense Line Description | Account | Total YTD Dec 2017 | NC Retail Jurisdictional Amount | Lead \ Lag Days | Weighted Amount |
|---|---|---|---|---|---|---|
| 1 | **OPERATING REVENUES:** | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | Service Lag | | | | 15.21 | |
| 5 | Billing Lag | | | | | |
| 6 | Total Retail Sales & Billing Lag | | (3,664,874,922) | (3,130,222,728) | 1.66 | |
| 7 | Revenue - REPS | | (43,981,207) | (43,981,207) | | |
| 8 | Unbilled Revenue | 0440.99, 0442.19, 0442.29, 0444.99, 0445.09 | (17,834,534) | (15,326,966) | | |
| 9 | | | | | | |
| 10 | Collection Lag | | | | 25.01 | |
| 11 | | | | | | |
| 12 | Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17) | | (3,726,690,663) | (3,189,530,901) | 41.88 | (133,572,238,249) |
| 13 | | | | | | |
| 14 | Total Revenue Lag Sales for Resale | | (1,257,931,461) | (98,547,668) | 33.73 | (3,324,012,842) |
| 15 | Provisions For Rate Refunds | 0449100 | 0 | - | | |
| 16 | Total Sales of Electricity (L12 + L14) | | (4,984,622,123) | (3,288,078,569) | 41.63 | (136,896,251,091) |
| 17 | | | | | | |
| 18 | Other Revenues: | | | | | |
| 19 | Forfeited Discounts | 0450100, 0450200 | (8,481,360) | (7,563,655) | 72.30 | (546,852,257) |
| 20 | Miscellaneous Revenues | 0451100 | (7,667,672) | (6,838,010) | 76.00 | (519,688,760) |
| 21 | RENT - (454) - DIST PLT REL | | (4,610,121) | (4,022,537) | 41.63 | (167,458,215) |
| 22 | RENT - (454) - DIST POLE RENTAL REV | | (14,715,792) | (12,301,943) | 182.00 | (2,238,953,626) |
| 23 | RENT - (454) - TRANS PLT REL | | (676,819) | (404,749) | 41.63 | (16,849,701) |
| 24 | RENT - (454) - ADD FAC - WHLS | | (3,290,570) | 0 | 0.00 | - |
| 25 | RENT - (454) - ADD FAC - RET X LIGHTING | | (6,228,691) | (5,640,043) | 41.63 | (234,794,990) |
| 26 | RENT - (454) - ADD FAC - LIGHTING | | (4,491,301) | (4,188,657) | 41.63 | (174,373,791) |
| 27 | RENT - (454) - OTHER | | (7,484,770) | (4,960,817) | 68.21 | (338,385,893) |
| 28 | OTHER ELEC REV (456) - PROD PLT REL | | (1,957,142) | (1,200,457) | 41.88 | (50,273,138) |
| 29 | OTHER ELEC REV (456) - TRANS REL | | (10,150,455) | (6,070,143) | 41.88 | (254,207,472) |
| 30 | OTHER ELEC REV (456) - GEN PLT REL | | 0 | 0 | 41.88 | - |
| 31 | OTHER ELEC REV (456) - WH D/A | | (62,938,028) | 0 | 41.88 | - |
| 32 | OTHER ELEC REV (456) - OTHER | | (5,950,637) | (3,944,012) | 41.88 | (165,168,670) |
| 33 | OTHER ELEC REV (456) - REPS | | (178,392) | (178,392) | 41.88 | (7,470,760) |
| 34 | OTHER ELEC REV (456) - OTHER ENERGY | | 0 | 0 | 41.88 | - |
| 35 | OTHER ELEC REV (456) - DIST PLT REL | 0456630 | (2,240,720) | (1,955,129) | 41.88 | (81,877,563) |
| 36 | Total Other Revenues (L19 through L35) | | (141,062,469) | (59,268,545) | 80.93 | (4,796,354,836) |
| 37 | | | | | | |
| 38 | **Utility Oper Revenues (L17 + L20+ L22 +L24 + L26 + L47 +L49 + L79)** | | (5,125,684,592) | (3,347,347,114) | 42.33 | (141,692,605,927) |
| 39 | ELECTRIC OPERATING REVENUE | | (5,125,684,592) | (3,347,347,114) | | |
| 40 | | | | | | |
| 41 | **OPERATION AND MAINTENANCE EXPENSE:** | | | | | |
| 42 | | | | | | |
| 43 | **Fuel Used in Electric Generation** | | | | | |
| 44 | OM Prod Energy - Fuel | | 1,251,419,297 | 762,662,565 | 28.62 | 21,827,402,600 |
| 45 | | | | | | |
| 46 | **Fuel Used in Elec Gen (HFM Greenbook I/S)** | F_FUEL_USED_ELEC_GEN | **1,251,419,297** | **762,662,565** | **28.62** | **21,827,402,600** |
| 47 | | | | | | |
| 48 | OM PROD PURCHASES - CAPACITY COST | | 116,417,717 | 71,407,405 | 30.29 | 2,162,930,289 |
| 49 | OM PROD PURCHASES - ENERGY COST | | 415,529,536 | 252,829,640 | 30.29 | 7,658,209,782 |
| 50 | OM DEFERRED FUEL EXPENSE | 0557980 | (180,732,923) | (180,189,502) | 0.00 | - |
| 51 | **Purchased Power (Acct 555) + Def Fuel (Acct 557)** | 0555XXX | **351,214,330** | **144,047,542** | **68.18** | **9,821,140,071** |
| 52 | | | | | | |

| Line No. | Total Utility Operating Revenue and Expense Line Description | Account | Total YTD Dec 2017 | NC Retail Jurisdictional Amount | Lead \ Lag Days | Weighted Amount |
|---|---|---|---|---|---|---|
| 53 | **Total Other O&M Excluding Fuel and Purchased Power** | | | | | |
| 54 | | | | | | |
| 55 | Total Labor Expense | | 562,409,999 | 366,460,746 | 31.67 | 11,604,542,579 |
| 56 | | | | | | |
| 57 | Uncollectible Amounts | 0904000, 0904001 | 6,504,470 | 5,800,670 | 0.00 | - |
| 58 | | | | | | |
| 59 | Nuclear Fees in Acct 524 | 0524000 | 34,582,782 | 21,212,121 | (34.66) | (735,212,115) |
| 60 | | | | | | |
| 61 | Pension and Benefits | 0926XXX | 90,966,042 | 59,272,566 | 14.23 | 843,448,608 |
| 62 | | | | | | |
| 63 | Regulatory Commission Expense | 0928000 | 7,127,626 | 5,592,954 | 103.01 | 576,130,192 |
| 64 | | | | | | |
| 65 | Property Insurance | 0924XXX | 7,696,581 | 5,184,875 | (222.30) | (1,152,597,643) |
| 66 | | | | | | |
| 67 | Injuries & Damages - Workman's Compensation | 0925980 | 288,240 | 194,176 | 0.00 | - |
| 68 | | | | | | |
| 69 | Remaining Other Oper & Maint Expense | | 652,535,859 | 457,582,404 | 44.01 | 20,138,201,601 |
| 70 | | | | | | |
| 71 | Total O&M Excl. Fuel and Purch. Power | | 1,362,111,599 | 921,300,511 | 33.95 | 31,274,513,222 |
| 72 | | | | | | |
| 73 | **Total Operation and Maintenance Expense (L46 + L51 + L69)** | | **2,964,745,226** | **1,828,010,618** | **34.42** | **62,923,055,892** |
| 74 | | | | | | |
| 75 | Total Depreciation & Amortization & Property Loss | | 762,731,492 | 539,354,933 | 0.00 | - |
| 76 | | | | | | |
| 77 | **Taxes Other Than Income Taxes** | | | | | |
| 78 | Payroll Taxes | | 37,286,697 | 24,282,736 | 11.31 | 274,637,739 |
| 79 | Property Tax | | 95,736,515 | 64,423,155 | 186.50 | 12,014,918,316 |
| 80 | FED HEAVY VEHICLE USE TAX | | 45,282 | 35,860 | 0.00 | - |
| 81 | ELECTRIC EXCISE TAX - SC | | 2,436,779 | - | 0.00 | - |
| 82 | PRIVILEGE TAX | | 16,254,008 | 12,031,302 | (11.97) | (144,014,686) |
| 83 | PUC LICENSE TAX - SC | | 1,775,775 | - | 0.00 | - |
| 84 | Taxes Other Than Income Taxes | | 153,535,056 | 100,773,052 | 120.52 | 12,145,541,369 |
| 85 | | | | | | |
| 86 | Total Interest on Customer Deposits | | 9,367,221 | 8,712,804 | 137.50 | 1,198,010,503 |
| 87 | | | | | | |
| 88 | Federal Income Tax | | (91,946,206) | (66,117,748) | 44.75 | (2,958,769,227) |
| 89 | State Income Tax | | 2,562,304 | 1,842,531 | 44.75 | 82,453,280 |
| 90 | Income Tax - Deferred | | 426,155,043 | 314,669,695 | 0.00 | - |
| 91 | Net Income Taxes | | 336,771,141 | 250,394,479 | (11.49) | (2,876,315,948) |
| 92 | | | | | | |
| 93 | Investment of Tax Credit Adj Net | 04114XX | (3,380,372) | (2,136,868) | 0.00 | - |
| 94 | | | | | | |
| 95 | **Total Utility Operating Expenses (L138 + L140 + L147 + L149 + L151 + L153)** | | 4,223,769,763 | 2,725,109,018 | 26.93 | 73,390,291,817 |
| 96 | | | | | | |
| 97 | Interest Expense for Electric Operations | | 281,071,586 | 186,290,919 | 0.00 | - |
| 98 | Income for Return (L92 + L94) | | (620,843,243) | 435,947,177 | 0.00 | - |
| 99 | Net Utility Operating Income | | 901,914,829 | 622,238,096 | 0.00 | - |
| 100 | | | | | | |
| 101 | Total Requirements (Ln 269+273) | | 5,125,684,592 | 3,347,347,114 | 21.92 | 73,390,291,817 |
| 102 | | | | | | |
| 103 | | | | | | |
| 104 | Cash Working Capital Related to NC Sales Tax | | 5,841,335 | | | |

# Duke Energy Corporation

## Independent Lobbying Labor Cost Study

August 31, 2016

**KPMG LLP**
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Internet www.us.kpmg.com

William E. Currens, J
Controller, Senior Vice President, Chief Accounting Officer
Duke Energy Business Services LLC
PO Box 37929
Mail Code ST29B
Charlotte, NC 28237

Dear Mr. Currens,

On behalf of KPMG LLP (KPMG), thank you for the opportunity to assist Duke Energy Business Services LLC (DEBS) in the preparation of the independent labor cost study as stipulated in FERC Docket PA-14-2-000 for Duke Energy Corporation and its public utility subsidiaries (Duke Energy). Transmitted herewith is our study report, which is comprised of an executive summary and three separate sections that address each of the deliverables and activities we were requested to perform as described below:

- Lobbying Labor Cost Policy Review
- Comparative Analysis
- Lobbyist Survey

KPMG's services constituted an Advisory engagement conducted under the American Institute of Certified Public Accountants ("AICPA") Standards for Consulting Services. Such services are not intended to be an audit, examination, attestation, special report or agreed-upon procedures engagement as those services are defined in AICPA literature applicable to such engagements conducted by independent auditors. Accordingly, these services do not result in the issuance of a written communication to third parties by KPMG directly reporting on financial data or internal control or expressing a conclusion or any other form of assurance.

The observations and recommendations contained in this report are those that we could reasonably derive from the scope of services performed. KPMG has no responsibility for follow-up on our recommendations nor for the ultimate disposition by management of our recommendations. Any eventual implementation of our recommendations including policy decisions are solely the responsibility of Duke Energy management.

The data included in this report was obtained from you and other publicly available sources, as detailed in the report, on or before August 31, 2016. We have no obligation to update our report or to revise the information contained therein to reflect events and transactions occurring subsequent to August 31, 2016.

KPMG cannot guarantee that regulatory authorities would agree with our analysis or that our engagement would foreclose or limit any potential regulatory action. Further, our review may not identify all rating or regulatory issues that may exist or that may become apparent in the future. KPMG's role in

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this engagement was to identify,analyze and summarize the factual information from the publicly available data and/or management provided data. KPMG cannot support or advocate any policy positions as a result of our observations. Should KPMG's participation be requested in Duke Energy meetings or hearings with government officials to explain our review and analysis from a technical perspective, KPMG's participation cannot include private meetings with legislators or occur in a context that could be fairly interpreted as public policy advocacy, lobbying, or otherwise be perceived as impairing our independence.

The scope of work did not require that KPMG make any legal interpretations or render any legal advice, and KPMG and the Company agreed that KPMG's services would not include nor be construed to include the provision by KPMG of legal advice or legal services. All legal interpretations and rendering of legal advice is the Company's responsibility.

We sincerely enjoyed the opportunity to have worked with you and other key DEBS and Duke Energy state lobbyist executives, directors, managers and support staff who have ongoing involvement in compliance related matters and appreciate the input and guidance we received from them over the course of our engagement.

Very truly yours,

KPMG LLP

Thomas R. Peterson

Thomas R. Peterson
Engagement Managing Director
thomaspeterson@kpmg.com
818 852 6131

# Contents

# Executive Summary

## Overview

KPMG performed an independent[1] study of Duke Energy's affiliates' federal and state cost allocations of internal lobbyist labor, related support staff labor, and associated non-labor costs that should be accounted for in operating and non-operating accounts based on our understanding of Federal Energy Regulatory Commission ("FERC") regulations.

The FERC required Duke Energy to retain an independent third-party entity to conduct a representative labor time study and to determine an appropriate allocation of lobbying costs based on time spent by employees engaged in the activities. The Study is required to be submitted to the FERC by September 28, 2016.[2]

## Study components

This Study is comprised of three separate sections as outlined below:

1. Lobbying Labor Cost Allocation Policy Review
    - Federal and State Policy Review
    - Duke Energy Corporation Policy Review
2. Comparative Analysis
    - FERC Form 60, Schedules XV, XVI, and XVII
    - Lobbying Labor Cost Allocation Methods
3. Lobbyist Survey

## Scope of Work

KPMG's work is to perform an independent study ("Report" or "Study") of Duke Energy's affiliates' federal and state lobbyists' cost allocations of internal lobbyist labor, support staff, and associated costs that could be accounted for in operating and non-operating accounts based on our understanding of Federal Energy Regulatory Commission ("FERC") regulations.

For the purpose of this study, KPMG's services constituted an Advisory engagement conducted under the American Institute of Certified Public Accountants ("AICPA") Standards for Consulting Services. Such services are not intended to be an audit, examination, attestation, special report or agreed-upon procedures engagement as those services are defined in AICPA literature applicable to such

[1] For purposes of this report, the term "independent" as used herein is not such term as defined by the American Institute of Certified Public Accountants ("AICPA") or other local regulatory authorities in connection with, among other things, audits, reviews, compilations or other attestation services rendered by Certified Public Accountants. The term "independent" as used herein means that KPMG does not have any financial or other relationships with the Company or affiliates that would preclude KPMG from providing you this report for purposes of responding and filing a report with the FERC.

[2] Refer to Summary Finding 28, page 7, FERC Docket PA-14-2-000 dated March 29, 2016

engagements conducted by independent auditors. Accordingly, these services do not result in the issuance of a written communication to third parties by KPMG directly reporting on financial data or internal control or expressing a conclusion or any other form of assurance.

The scope of work did not call upon KPMG to make any legal interpretations or render any legal advice, and KPMG and the Company agreed that KPMG's services would not include nor be construed to include the provision by KPMG of legal advice or legal services. All legal interpretations and rendering of legal advice is the Duke Energy's responsibility.

## Summary level observations and recommendations

Summary level observations and recommendations for each of the three sections of this study are presented below. Supporting documentation for each section, including review, assessment, and survey activities and procedures performed and detailed observations and recommendations, is presented within the body of the Study and associated Appendices.

Section I: Lobbying Labor cost policy review

*Purpose:*

KPMG reviewed Federal and individual state policies for recording lobbying related expenditures to FERC Account 426.4 as defined under the Code of Federal Regulations (CFR) Section 367.4264 to understand if there were any major guideline differences between the jurisdictions in which Duke Energy operates.

*Observations:*

a) We found that in general, all jurisdictions follow the lobbying definitions noted in CFR Section 367.4264 for reporting purposes. Some states, such as Indiana, may have more restrictive lobbying definitions, however Duke Energy policies follow the Federal guidelines and, if necessary, will adjust for any state jurisdictional differences from the CFR for jurisdictional reporting or rate case purposes.

*Recommendations:*

a) None

Section II: Comparative analysis, including FERC Form 60, Schedules XV, XVI, and XXI

Most utility holding companies deploy lobbying resources through a centralized services company, and Duke Energy is no exception. Of the 32 direct lobbyist and support personnel identified by Duke Energy and included in this Study, 23 (72%) were deployed by DEBS and therefore subject to the reporting requirements of the FERC Financial Report Form No. 60: Annual Report of Centralized Service Companies ("FERC Form 60"). The following represent a summary of the analyses performed.

**1) FERC Form 60, Schedule XV – Account 426.4 expenses as a percentage of Total Operating Expenses.**

Purpose: Schedule XV reports a comparative income statement for utility service companies, with Line 37 detailing expenditures related to Account 426.4. The purpose of this review was to understand any major gaps in DEBS charges to this account compared to the peer group[3] as obtained from the 2015 Form 60 publicly available reports.

[3] The peer group is defined further in Section II of this Study.

*Observations:*

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XV data revealed Account 426.4 expenditures for DEBS was 0.41% of total operating expenses. The peer group average was .37% with a median of .31%.

*Recommendations:*

a) None

**2) FERC Form 60, Schedule XVI – Direct Account 426.4 expenses as a percentage of Total Account 426.4 Expenses.**

Purpose: Schedule XVI reports direct and indirect charges to affiliate and non-affiliate companies with Line 25 outlining Account 426.4 expenditures. The purpose of this assessment was to gain a better understanding of how lobbying expenses are charged to the account relative to the peer group as obtained from publicly available FERC Form 60 reports for the calendar year ended 2015.

*Observations:*

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XVI data revealed that Direct Account 426.4 expenditures as a percentage of total Account 426.4 expenditures for DEBS was 33% The peer group average was 70% with a median result of 51%.

b) The range of the peer group averages was quite wide (0% to 99%) indicating that the standard industry definition being used in the application of Form 60 "direct" versus "indirect" charges to the account may be more of a function of how the peer group service companies are organized within their respective operating systems. That is, if all system lobbying resources reside in the service company, direct charges to associated companies would be higher on average. If only lobbying management and Federal lobbying resources reside in the service company, direct charges to associated companies would be lower on average.

c) Discussions with DEBS Finance personnel revealed that 12 of the 23 DEBS resources (52%) are reporting through the Federal External Affairs and Strategy Policy function which by nature requires a general, or indirect, allocation to affiliate customers. The makeup of DEBS lobbying resources would point toward a lower direct charge ratio relative to peers.

d) Discussions with DEBS Finance personnel noted that the Duke Energy deploys a charge code approach that allows all lobbying resources (both residing in DEBS and in the local state jurisdictions) the opportunity to directly charge the benefitting company. The ability to direct charge is reinforced with all system-wide lobbying resources through annual training and educational programs.

*Recommendations:*

a) None – Duke Energy was not an outlier relative to the peer group and should continue to promote the use of direct charging mechanisms with lobbying personnel system-wide.

**3) FERC Form 60, Schedule XXI – Methods of Allocation.**

Purpose: Schedule XXI reports how utility service companies bill *indirect* charges through allocation methodologies to affiliate and non-affiliate customers. The purpose of this assessment was to understand if billings to associated companies applied on a basis similar to that used in the industry relative to the peer group as obtained from publicly available FERC Form 60 reports for calendar year ended 2015.

*Observations:*

a) DEBS uses a "3-factor formula" based on the weighted average gross margin ratio, labor dollars ratio, and the property, plant and equipment ratio for allocation purposes to bill utility subsidiaries. This factor is included in DEBS yearly Cost Allocation Manual submission to the FERC for approval.

b) Review of peer group Form 60, Schedule XXI noted similar "general" allocators used for this cost pool.

*Recommendations:*

a) None

## Section III: Lobbyist Survey

The purpose of the Lobbyist Survey was to develop a time labor study for use by Duke Energy system companies as a basis for allocation of labor related costs to the appropriate accounts. The scope of the Study included all personnel within the Duke Energy system companies associated with lobbying functions, whether performing direct lobbyist or general lobbying support activities.

*Observations:*

a) Activity group 1.0 – Manage External Relationships represents the overall system percentage (53%) that would be applied to the Below-The-Line CFR Account 426.4. Activity group 2.0 – Manage Internal Relationships represents the overall system percentage (47%) that would be applied to the Above-The-Line CFR Account 920.0.

b) Total system results noted above represent only the simple average of all respondents and are not dollar weighted. Results also vary by individual and by the jurisdiction for which the services were provided.[4]

*Recommendations:*

a) Duke Energy should apply the detailed study results for charges beginning January 1, 2016 and forward. We recommend the individual respondent survey results be applied to the time entry account code structures currently in place.

b) Duke Energy should institute policies and procedures to periodically update these study results to help ensure any changes in personnel or lobbyist activities are captured and adjusted. These procedures should ensure that any material changes in personnel or responsibilities can be identified and updated on a case by case basis if required.

c) Duke Energy should continue to reinforce and promote the ability to set up specific project charge codes for individuals to capture and assign time and expenses that are outside the parameters of the time labor study activities.

[4] Results by jurisdiction are provided in Appendix D of this report and results by individual are provided in Appendix E of this report.

# Section I: Lobbying Labor Cost Policy Review

## Purpose and scope

The purpose of this work was to review Duke Energy's and their respective utility subsidiaries'[5] existing requirements for lobbying costs relative to industry standards. KPMG conducted interviews[6] with lobbying and regulatory personnel, and reviewed documentation requests[7] to understand how costs were being both assigned and recovered under Federal and / or state requirements. In general, charges to Account 426.4 (defined below) are not included or recoverable for ratemaking purposes.

Duke Energy operates in 5 states and 11 separate jurisdictions for rate purposes[8], including the Federal function in which costs are captured at the service company level (DEBS) and subsequently billed to the jurisdictional entities through allocations. The lobbying function is organized with resources located at both the DEBS level and within the individual state subsidiaries. Of the 32 lobbying resources, both management and support, 23 are located within DEBS.

## Federal and state policy review

Federal requirements for lobbying costs are found in the Code of Federal Regulations ("CFR") Section 367.4264 which states:

Account 426.4, Expenditures for certain civic, political and related activities

a) This account must include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials.

b) This account must not include expenditures that are directly related to appearances before regulatory or other governmental bodies in connection with an associate utility company's existing or proposed operations.

State policies generally have adopted the CFR Section 367.4264 definitions noted above with the one exception of Indiana. Indiana Code 2-7-1-9 appears to be more restrictive by defining "lobbying" as *only* communicating by any means, or paying others to communicate by any means, with any legislative person for the purpose of influencing any legislative action. All states within the Duke Energy system require periodic report submittals of internal lobbying costs and related expenditures.

## Duke Energy Corporation policy review

Duke Energy system companies, based on our interviews, have adopted the CFR accounting requirements and definitions as noted above for compliance and recording purposes.

[5] The scope of this Study did not include any review of internal control procedures or management oversight of those procedures to provide assurance that time reporting and tracking was being followed.
[6] A complete listing of Duke Energy personnel interviewed can be found in Appendix A.
[7] A complete listing of documents reviewed can be found in Appendix B.
[8] See Appendix C for a complete listing as was used in the Lobbyist Survey – Format.

## Observations and recommendations

*Observations:*

a) We found that in general, all jurisdictions follow the lobbying definitions noted in CFR Section 367.4264 for reporting purposes. Some states, such as Indiana, may have more restrictive lobbying definitions, however Duke Energy follows the Federal guidelines and, if necessary, will adjust for any state jurisdictional differences from the CFR for jurisdictional reporting or rate case purposes.

*Recommendations:*

a) None

# Section II: Comparative Analysis

## Purpose and scope

The purpose of this work was to assess Duke Energy's current environment compared to a sample of other utility holding companies with respect to lobbying costs charged to Account 426.4 - Expenditures for certain Civic, Political and Related activities. The analysis was performed to assess the gaps between DEBS and other comparable utility services companies.

Most utility holding companies deploy lobbying resources through a centralized services company, and Duke Energy is no exception. Of the 32 direct lobbyist and support personnel identified by Duke Energy and included in this Study, 23 (72%) were deployed by DEBS and therefore subject to the reporting requirements of the FERC Financial Report Form No. 60: Annual Report of Centralized Service Companies ("FERC Form 60").

Results of this analysis provided KPMG with information to corroborate interview needed for development of the labor study noted in Section III of this report. KPMG utilized the publicly available FERC Form 60 submittals for the following selected metrics and compared DEBS results to those of a peer group comprised of seven (7) utility service companies with similar financial, operational, and jurisdictional characteristics.

- Civic, Political, and Related Expenditures (Account 426.4) as a percentage of Operating Expenses as stated on FERC Form 60, Schedule XV.

- Direct[9] Civic, Political, and Related Expenditures (Account 426.4) as a percentage of Total Civic, Political, and Related Expenditures as stated on FERC Form 60, Schedule XVI.

The peer group was comprised of the following entities which were discussed with Duke Energy prior to the commencement of work:

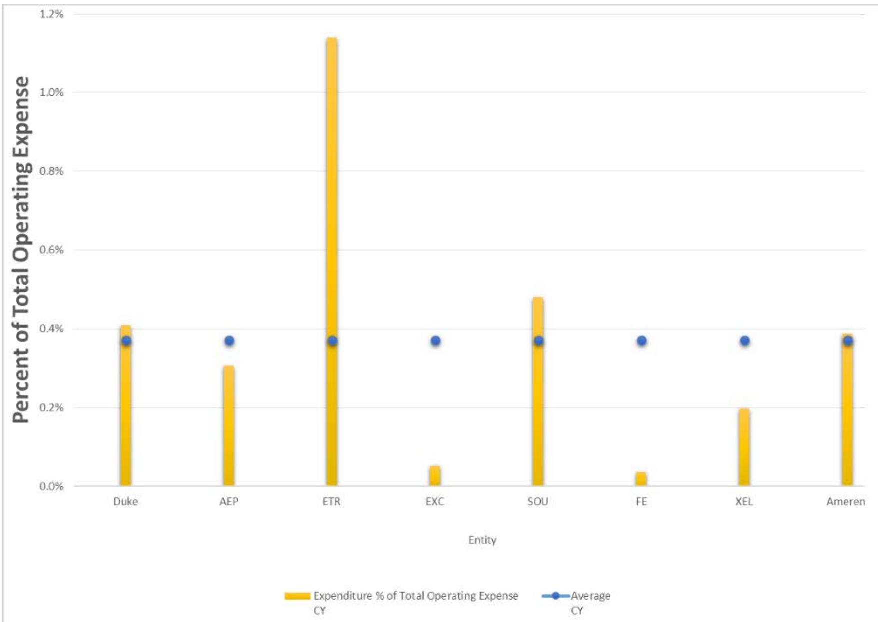
- American Electric Power Service Corporation (AEP)
- Ameren Services Company (Ameren)
- Entergy Services, Incorporated (ETR)
- Exelon Business Services Company, LLC (EXC)
- FirstEnergy Services Company (FE)
- Southern Company Services, Incorporated (SOU)
- Xcel Energy Services Incorporated (XEL)

[9] The term "Direct" with regard to a FERC Form 60 means charges from the service company function that were not allocated to system affiliate customers using some type of general formula.

# FERC filings

**FERC Form 60, Schedule XV – Account 426.4 expenses as a percentage of Total Operating Expenses**

Schedule XV reports a comparative income statement for utility service companies, with Line 37 detailing expenditures related to Account 426.4. The chart below highlights the results from each of the peer group service company data relative to DEBS.




Account 426.4 Expenditures as a Percent of Total Operating Expenses - 2015

*Observations:*

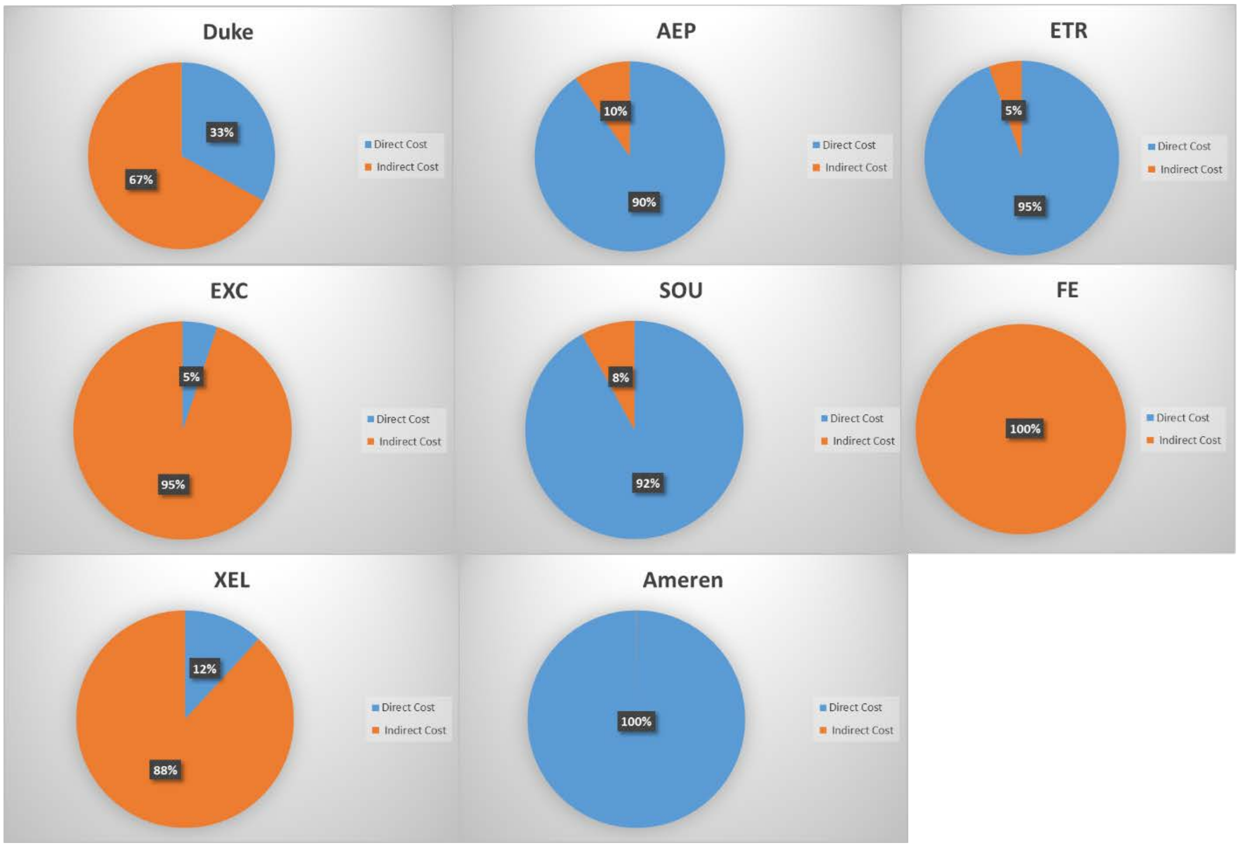
a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XV data revealed Account 426.4 expenditures for DEBS was 0.41% of total operating expenses. The peer group average was .37% with a median of .31%.

*Recommendations:*

a) None

**FERC Form 60, Schedule XVI – Direct Account 426.4 expenses as a percentage of Total Operating Expenses**

Schedule XVI reports direct and indirect charges to affiliate and non-affiliate companies with Line 25 outlining Account 426.4 expenditures. The following charts show the percentage of direct to indirect charges for each of the peer group companies.




Account 426.4 Expenditures - Associate Company Direct vs. Indirect cost

*Observations:*

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XVI data revealed that direct Account 426.4 expenditures as a percentage of total Account 426.4 expenditures for DEBS was 33% The peer group average was 70% with a median result of 51%.

b) The range of the peer group averages was quite wide (0% to 99%) indicating that the standard industry definition being used in the application of Form 60 “direct” versus “indirect” charges to the account may be more of a function of how the peer group service companies are organized within their respective operating systems. That is, if all system lobbying resources reside in the service company, direct charges to associated companies would be higher on average. If only lobbying management and Federal lobbying resources reside in the service company, direct charges to associated companies would be lower on average.

c) Discussions with DEBS Finance personnel revealed that 12 of the 23 DEBS resources (52%) are reporting through the Federal External Affairs and Strategy Policy function which by nature requires a general, or indirect, allocation to affiliate customers. The makeup of DEBS lobbying resources would point toward a lower direct charge ratio relative to peers.

d) Discussions with DEBS Finance personnel noted that the Duke Energy deploys a charge code approach that allows all lobbying resources (both residing in DEBS and in the local state jurisdictions) the opportunity to directly charge the benefitting company. The ability to direct charge is reinforced with all system-wide lobbying resources through annual training and educational programs.

*Recommendations:*

a) None – Duke Energy should continue to promote the use of direct charging mechanisms with lobbying personnel system-wide.

**FERC Form 60, Schedule XXI – Methods of Allocation**

Schedule XXI reports how utility service companies allocate indirect charges to affiliate and non-affiliate customers. Costs for shared services are distributed to affiliates within Duke Energy through (i) direct charges, (ii) distribution or (iii) allocation. Costs are direct charged to the extent possible. Costs that cannot be direct charged can be distributed to the applicable business units using specific percentages if known. Costs that cannot be direct charged or distributed are allocated to the business units receiving the benefit using reasonable allocation methods.

*Observations:*

a) DEBS uses a "3-factor formula" based on the weighted average gross margin ratio, labor dollars ratio, and the property, plant and equipment ratio for allocation purposes to bill utility subsidiaries. This factor is included in DEBS yearly Cost Allocation Manual submission to the FERC for approval.

b) Review of peer group Form 60, Schedule XXI noted similar "general"[10] allocators used for this cost pool.

*Recommendations:*

a) None

[10] The term "general" allocators used herein refers to methods in which multiple utility entities are billed by their respective services company. For example, Exelon uses a Modified Massachusetts Formula (MMF) which uses a combination of gross revenues, assets and direct labor that is commonly used in the industry. Xcel Energy uses another type of general allocator also termed the 3-factor formula which uses a combination of revenues, employees and total assets. FirstEnergy uses a general allocator termed "Multiple Factor Utility". All of these general allocators are reviewed and approved by FERC.

# Section III: Lobbyist Survey

## Purpose and scope

The purpose of the Lobbyist Survey and related steps was to conduct a time labor study for use by Duke Energy system companies as a basis for allocation of labor related lobbying costs to the appropriate accounts. The scope of the Study included all personnel within the Duke Energy system companies associated with lobbying functions, whether performing direct lobbyist or general support activities for the lobbying functions.

As background, Duke Energy system companies deploy a system of time reporting that allows all employees to directly charge or distribute activity costs to the proper utility or jurisdiction at time entry. Study results can be applied to the direct or distributed charge codes utilized for allocation of costs either to CFR account 426.4 ("Below the line") or CFR account 920.0 ("Above the line").

The Study did not assess or include Federal or state jurisdictional rate treatment of these costs subsequent to the initial allocations to the accounts noted above.

## Approach

The lobbyist survey approach is depicted below:

1. Develop Lobbying Cost Survey – through a series of interviews with select Duke Energy lobbyist and support staff, as well as the review of internal Duke Energy or DEBS documentation related to lobbying costs, KPMG developed a survey based on typical activities that would be performed throughout the year. The complete survey, along with instructions, examples and structure, can be found in Appendix C.

2. Distribute Lobbying Cost Survey – surveys were electronically distributed to all lobbyist and support personnel identified by Duke Energy. Individuals were instructed to complete the survey and send the individual results directly back to KPMG.

3. Review and Assess Lobbying Cost Survey – Upon receipt of all surveys, KPMG then analyzed and summarized the results by person and by jurisdiction. Part of the analysis involved going back to certain individuals to validate their individual survey responses.[11]

## Summarized survey responses

The following represents a high level summary of the Duke Energy system-wide survey responses by primary activity level. Detailed survey results have been supplied to Duke Energy.

[11] All survey validated results are located in the detail Survey workpapers supplied to Duke Energy

| Total System | | |
|---|---|---|
| | Primary Lobbying Activity Groups | Breakdown |
| 1.0 | Manage External Relationships | 53% |
| 1.1 | Provide Direct Lobbying Services - Federal | 8% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 17% |
| 1.3 | Evaluate and Communicate Strategic Positions | 17% |
| 1.4 | Develop and Maintain Relationships | 12% |
| 2.0 | Manage Internal Relationships | 47% |
| 2.1 | Provide Internal Lobbying Services | 16% |
| 2.2 | Provide Internal Non-Lobbying Services | 12% |
| 2.3 | Provide Other Operational Services | 19% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

## Observations and recommendations

*Observations:*

a) Activity group 1.0 – Manage External Relationships represents the overall system percentage (53%) that would be applied to the Below-The-Line CFR Account 426.4. Activity group 2.0 – Manage Internal Relationships represents the overall system percentage (47%) that would be applied to the Above-The-Line CFR Account 920.0.

b) Total system results noted above represent only the simple average of all respondents and are not dollar weighted. Results also vary by individual and by the jurisdiction for which the services were provided.[12]

*Recommendations:*

a) Duke Energy should apply the detailed study results for charges beginning January 1, 2016 and forward. We recommend the individual respondent survey results be applied to the time entry account code structures currently in place.

b) Duke Energy should institute policies and procedures to periodically update these study results to help ensure any changes in personnel or lobbyist activities are properly captured and adjusted. These procedures should ensure that any material changes in personnel or responsibilities can be identified and updated on a case by case basis if required.

d) Duke Energy should continue to reinforce and promote the ability to set up specific project charge codes for individuals to capture and assign time and expenses that are outside the parameters of the time labor study activities.

[12] Summarized results by jurisdiction and by individual are provided in Appendix D and Appendix E of this report, respectively

# Appendix A: Interview List

Over the course of this assessment, KPMG conducted a series of interviews with Duke Energy key lobbyist, support staff, regulatory and finance personnel to gain a better understanding of how costs flowed through the account systems and the types of activities performed. Key personnel who were interviewed included the following:

| Employee ID[13] | Title | Interview Group |
|---|---|---|
| 125669 | Managing Director Rates & Regulatory Strategy - Carolinas | Rates - Carolinas |
| 265672 | Director Federal Government Affairs SC | Lobbyist - Federal |
| 359638 | Vice President Indiana Government Affairs | Lobbyist - Indiana |
| 019577 | Director Rates & Regulatory Strategy-OH/KY | Rates - Ohio/Kentucky |
| 343011 | Director Rates & Regulatory Strategy-FL | Rates - Florida |
| 026641 | Director State Government Affairs | Lobbyist - Ohio |
| 010565 | Vice President Government & Community Affairs | Lobbyist - Kentucky |
| 358441 | Director State Government Affairs | Lobbyist - Florida |
| 122866 | Director Allocations & Reporting | DEBS - Cost Allocations |
| 369923 | Executive Assistant | Support Staff - Indiana |
| 153865 | Vice President Government Affairs | Lobbyist – South Carolina |
| 338568 | Senior Administrative Specialist | Support Staff – South Carolina |
| 284280 | Vice President Government Affairs-NC | Lobbyist – North Carolina |
| 112288 | Director Rates & Regulatory Planning | Rates - Indiana |
| 125764 | Manager Accounting | Rates - Transmission |

[13] For purposes of this publicly available report we use employee ID numbers rather than individual names.

# Appendix B: Documents Reviewed

Over the course of this assessment, KPMG requested and reviewed the following list of documents to gain a better understanding of how lobbyist costs flowed through the system of accounts.

| Document Name | Employee ID[14] |
|---|---|
| State Codes / Lobbying Definitions | 017666 |
| FERC audit work papers and FERC responses | 235377 |
| FERC Form 60s for 2014 & 2015 | 335729 |
| Time Capture Process Code Structures | 335729 |
| 2015 Actual Data Charges by Responsibility Center, Operating Unit, Business Unit, Process Code and Resource Type | 335729 |
| 2016 DEBS Allocation Tables | 122866 |
| 2013 DEBS Cost Allocation Manual | 122866 |
| Example Data request response to Customer advocacy group (NC) | 125669 |
| Spreadsheet example of all sources charging lobbying codes | 335729 |
| Federal "Heat Map" Presentation (Federal Issues Update) | 367150 |
| Copies of latest Indiana lobbyist reports and "Lobbying" definition | 359638 |
| Copy of the H-22 schedule from latest rate case (Ohio Kentucky) | 019577 |
| Copies of the C-18 schedules used in FLA rate case support | 343011 |
| Copy of South Carolina Lobbying definitions | 017666 |
| Copies of South Carolina Lobbying Ethics reports | 338568 |
| 2009 rate support schedules with proforma entries for lobbying | 112288 |

[14] For purposes of this publicly available report we use employee ID numbers rather than individual names.

# Appendix C: Labor Survey Structure

## Instructions: The following represents the instructions sent to all survey respondents.

| | |
|---|---|
| **1. INTRODUCTION** | **In response to a FERC merger audit finding regarding the allocation of lobbyist and support labor costs, Duke Energy engaged KPMG to perform an independent review of system-wide lobbyist labor costs and activities. The results of the study will be analyzed by KPMG and, along with any policy recommendations, a report will be prepared and filed with the FERC in late September, 2016.<br><br>It is also important to understand that the study and associated documentation will only be used on a going forward basis to provide support for time entry allocation purposes with periodic updates to substantiate and document sound policy and procedure. This is not an audit but a view forward, so any past practices or entrenched beliefs should be discounted.<br><br>The purpose of the study is to gain your individual input as a subject matter resource as to the amount of time spent in various activities. Study results will be treated as confidential with respect to the report, and KPMG may have follow up questions upon submittal.** |
| **2. REFERENCE GUIDE TAB** | **The tab entitled "Reference Guide" is for your use in understanding the types of activities and tasks being performed. This lobbyist "activity dictionary" was prepared using a combination of external sources and data request responses and the results of interviews performed with executive management, lobbyists and staff support personnel within the Duke system.<br><br>This survey preparation work resulted in a list of 16 common, yet representative, activities related to lobbying departments and functions.<br><br>Prior to filling out the Activity Survey Tab, we suggest you review the activity definitions and the associated example activities provided to gain a familiarity and to begin to formulate your individual estimates of time spent.** |
| **3. ACTIVITY SURVEY TAB** | **On the far left of the tab you will see the 16 activities listed under two processes, External and Internal facing relationship management. To the right of the activities listed are drop down cells containing increments of 5% and should be used to estimate your individual participation by the jurisdiction listed in Columns F-R. Please complete your estimate of time by jurisdiction and pay attention to Cell E-1 which will maintain a running total and turn "Green" when your sum total estimates equal 100%.<br><br>While every attempt to produce a relevant survey for your use was made, there may be an occasion in which a listed activity that you perform cannot be grouped within these categories. Therefore each activity grouping has a <blank> cell for you to fill out should you feel the need.<br><br>Additionally at the bottom of the survey chart, a blank notes / comments section has been provided for any feedback you deem required for us to better understand the results.<br><br>Finally, we understand that in any given business situation responsibilities may change, or special projects may come up. The purpose of the survey is to gain an understanding of what a typical year currently looks like for you. Special project work that has come up in the past or that may come up in the future should be directly charged to individual project codes set up by your Finance representative and not reflected here. Similarly if normal, ongoing business responsibilities change next year, that is understandable and would be taken care through the future periodic refreshes of this study.** |
| **4. SURVEY COMPLETION** | **We thank you in advance for your timely participation in this important study. Should you have any questions or problems, please feel free to email or call the KPMG project team: Mark Everette (markeverette@kpmg.com/312-560-9159) or Doug Centola (dcentola@kpmg.com/585-760-4492).<br><br>UPON COMPLETION, ALL RESPONSES SHOULD BE SENT DIRECTLY TO DOUG CENTOLA [dcentola@kpmg.com] by COB on 08/03/16.** |

# Appendix C: Labor Survey Structure

## Reference Guide

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

| Primary Lobbying Activity Groups | | Example Activities |
|---|---|---|
| 1.0 | Manage External Relationships | |
| 1.1 | Provide Direct Lobbying Services - Federal | |
| 1.1.1 | Contacting Congressional Members | • Contacting a member of Congress to discuss pending or proposed legislation, the company's opinion of pending legislation, a legislative proposal.<br>• Communication with a legislative body with regard to a decision, or possible decision, by the body which may, or may not be, consistent with the company's position.<br>• Managing and preparing testimony before a Congressional committee.<br>• Attending a Congressional committee or hearing (as a member of the audience). |
| 1.1.2 | Contacting Executive and Agency Officials | • Contacting an executive branch government or administrative official or employee who may participate in the formulation of legislation, where the principal purpose of the communication is to influence legislation.<br>• Holding meetings with agency officials to discuss legislative issues. |
| 1.1.3 | Contacting Members of the General Public | • Contacting members of the general public in a communication which refers to specific legislation, reflects a view on such legislation, and (directly or indirectly) encourages the recipient to take action.<br>• Attempting to influence the public in voting on a referendum. |

# Appendix C: Labor Survey Structure

## Reference Guide - Continued

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

| Primary Lobbying Activity Groups | | Example Activities |
|---|---|---|
| 1.0 | Manage External Relationships | |
| 1.2 | Provide Direct Lobbying Services –State and Local | |
| 1.2.1 | Contacting Congressional Members | • Contacting a member of Congress to discuss pending or proposed legislation, the company's opinion of pending legislation, a legislative proposal.<br>• Communication with a legislative body with regard to a decision, or possible decision, by the body which may, or may not be, consistent with the company's position.<br>• Managing and preparing testimony before a Congressional committee.<br>• Attending a Congressional committee or hearing (as a member of the audience). |
| 1.2.2 | Contacting Executive and Agency Officials | • Contacting an executive branch government or administrative agency official or employee who may participate in the formulation of legislation, where the principal purpose of the communication is to influence legislation.<br>• Holding meetings with agency officials to discuss legislative issues. |
| 1.2.3 | Contacting Members of the General Public | • Contacting members of the general public in a communication which refers to specific legislation, reflects a view on such legislation, and (directly or indirectly) encourages the recipient to take action.<br>• Attempting to influence the public in voting on a referendum. |

# Appendix C: Labor Survey Structure

## Reference Guide - Continued

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

| Primary Lobbying Activity Groups | | Example Activities |
|---|---|---|
| 1.0 | Manage External Relationships | |
| 1.3 | Evaluate and Communicate Strategic Positions | |
| 1.3.1 | Analyze and Draft Legislation | • Analyzing bills, laws and legislation and their impacts on or consistency with corporate strategy and priorities.<br>• Developing, drafting or editing legislation. |
| 1.3.2 | Develop, Monitor and Publish Research | • Conducting research to support a legislative initiative.<br>• Direct or publish analyses, studies, or research which reflects a view on specific legislation.<br>• Advocating a particular position or viewpoint within analyses, studies, or research to enable the public or an individual to form an independent opinion or conclusion. |
| 1.3.3 | Promote Strategic Positioning | • Conducting coalition meetings with other external organizations to share information to be used in lobbying and/or to devise lobbying strategy. |
| 1.4 | Develop and Maintain Relationships | |
| 1.4.1 | Promote Corporate Image | • Attending or participating in networking events on behalf of the Company.<br>• Attending or participating in charity or philanthropic events on behalf of the Company.<br>• Managing relationships with independent organizations (PACs, NGOs, Non-profits, etc.). |
| 1.4.2 | Manage Corporate Resources | • Managing and monitoring the funding of strategic sponsorships. |

# Appendix C: Labor Survey Structure

## Reference Guide - Continued

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

| Primary Lobbying Activity Groups | | Example Activities |
|---|---|---|
| 2.0 | Manage Internal Relationships | |
| 2.1 | Provide Internal Lobbying Services | |
| 2.1.1 | Communicate Strategy and Positions | • Communicating company positions and strategies on pending or proposed legislation to employees of Duke Energy.<br>• Contacting company personnel, departments and leadership to support lobbying efforts, to encourage legislative contact, and to promote Duke PAC membership. |
| 2.1.2 | Support Internal Lobbying Efforts | • Coordinating and meeting with internal departments or resources to support company positioning.<br>• Organizing and managing issues and strategies with other departments (such as Environmental, Community or Regulatory Affairs) to determine appropriate and consistent messaging on positions.<br>• Conducting advocacy training. |
| 2.2 | Provide Internal Non-Lobbying Services | |
| 2.2.1 | Manage or Support Other Departments | • Delivering any management or support activities (that are not associated with lobbying activities in 2.1 above) to other departments or functions within the company. |
| 2.3 | Provide Other Operational Services | |
| 2.3.1 | Manage Constituent Inquiries | • Assisting legislative officials with solving any constituent inquiries/issues (power outages, downed power lines, billing questions etc.). |
| 2.3.2 | Provide General Office Management Support | • Coordinating meetings, travel arrangements and training events.<br>• Managing executive calendars, supporting general office needs (facilities, supplies, technology support etc.).<br>• Processing and tracking invoices, time and expense coding and input, report generation and accounting. |

# Appendix C: Labor Survey Structure

## Format

The following represents the actual survey format sent to all respondents.

| | <NAME> | Estimated Percentage of Time Spent by Jurisdiction | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Primary Lobbying Activity Groups | Kentucky - Electric Only | Kentucky - Gas Only | Kentucky - All | Ohio - Electric Only | Ohio - Gas Only | Ohio - All | Indiana | North Carolina - DEC | North Carolina - DEP | South Carolina - DEC | South Carolina - DEP | Florida | Federal | Other - Specify |
| 1.0 | Manage External Relationships | | | | | | | | | | | | | | |
| 1.1 | Provide Direct Lobbying Services - Federal | | | | | | | | | | | | | | |
| 1.1.1 | Contacting Congressional Members | | | | | | | | | | | | | | |
| 1.1.2 | Contacting Executive and Agency Officials | | | | | | | | | | | | | | |
| 1.1.3 | Contacting Members of the General Public | | | | | | | | | | | | | | |
| 1.1.4 | <Other - please describe> | | | | | | | | | | | | | | |
| 1.2 | Provide Direct Lobbying Services –State and Local | | | | | | | | | | | | | | |
| 1.2.1 | Contacting Congressional Members | | | | | | | | | | | | | | |
| 1.2.2 | Contacting Executive and Agency Officials | | | | | | | | | | | | | | |
| 1.2.3 | Contacting Members of the General Public | | | | | | | | | | | | | | |
| 1.2.4 | <Other - please describe> | | | | | | | | | | | | | | |
| 1.3 | Evaluate and Communicate Strategic Positions | | | | | | | | | | | | | | |
| 1.3.1 | Analyze and Draft Legislation | | | | | | | | | | | | | | |
| 1.3.2 | Develop, Monitor and Publish Research | | | | | | | | | | | | | | |
| 1.3.3 | Promote Strategic Positioning | | | | | | | | | | | | | | |
| 1.3.4 | <Other - please describe> | | | | | | | | | | | | | | |
| 1.4 | Develop and Maintain Relationships | | | | | | | | | | | | | | |
| 1.4.1 | Promote Corporate Image | | | | | | | | | | | | | | |
| 1.4.2 | Manage Corporate Resources | | | | | | | | | | | | | | |
| 1.4.3 | <Other - please describe> | | | | | | | | | | | | | | |
| 2.0 | Manage Internal Relationships | | | | | | | | | | | | | | |
| 2.1 | Provide Internal Lobbying Services | | | | | | | | | | | | | | |
| 2.1.1 | Communicate Strategy and Positions | | | | | | | | | | | | | | |
| 2.1.2 | Support Internal Lobbying Efforts | | | | | | | | | | | | | | |
| 2.1.3 | <Other - please describe> | | | | | | | | | | | | | | |
| 2.2 | Provide Internal Non-Lobbying Services | | | | | | | | | | | | | | |
| 2.2.1 | Manage or Support Other Departments | | | | | | | | | | | | | | |
| 2.2.2 | <Other - please describe> | | | | | | | | | | | | | | |
| 2.3 | Provide Other Operational Services | | | | | | | | | | | | | | |
| 2.3.1 | Manage Constituent Inquiries | | | | | | | | | | | | | | |
| 2.3.2 | Provide General Office Management Support | | | | | | | | | | | | | | |
| 2.3.3 | <Other - please describe> | | | | | | | | | | | | | | |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | | | | | | | | | | | GRAND TOTAL | | | 0 |

# Appendix D: Labor Survey Results by Jurisdiction

**Kentucky**

| Primary Lobbying Activity Groups | | Breakdown |
|---|---|---|
| 1.0 | Manage External Relationships | 52% |
| 1.1 | Provide Direct Lobbying Services - Federal | 3% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 14% |
| 1.3 | Evaluate and Communicate Strategic Positions | 16% |
| 1.4 | Develop and Maintain Relationships | 19% |
| 2.0 | Manage Internal Relationships | 48% |
| 2.1 | Provide Internal Lobbying Services | 10% |
| 2.2 | Provide Internal Non-Lobbying Services | 21% |
| 2.3 | Provide Other Operational Services | 17% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

**OHIO**

| Primary Lobbying Activity Groups | | Breakdown |
|---|---|---|
| 1.0 | Manage External Relationships | 65% |
| 1.1 | Provide Direct Lobbying Services - Federal | 0% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 24% |
| 1.3 | Evaluate and Communicate Strategic Positions | 26% |
| 1.4 | Develop and Maintain Relationships | 14% |
| 2.0 | Manage Internal Relationships | 35% |
| 2.1 | Provide Internal Lobbying Services | 17% |
| 2.2 | Provide Internal Non-Lobbying Services | 9% |
| 2.3 | Provide Other Operational Services | 8% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

# Appendix D: Labor Survey Results by Jurisdiction

## Indiana

| Primary Lobbying Activity Groups | | Breakdown |
|---|---|---|
| 1.0 | Manage External Relationships | 41% |
| 1.1 | Provide Direct Lobbying Services - Federal | 0% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 23% |
| 1.3 | Evaluate and Communicate Strategic Positions | 7% |
| 1.4 | Develop and Maintain Relationships | 10% |
| 2.0 | Manage Internal Relationships | 59% |
| 2.1 | Provide Internal Lobbying Services | 12% |
| 2.2 | Provide Internal Non-Lobbying Services | 21% |
| 2.3 | Provide Other Operational Services | 26% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

## North Carolina

| Primary Lobbying Activity Groups | | Breakdown |
|---|---|---|
| 1.0 | Manage External Relationships | 71% |
| 1.1 | Provide Direct Lobbying Services - Federal | 0% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 28% |
| 1.3 | Evaluate and Communicate Strategic Positions | 22% |
| 1.4 | Develop and Maintain Relationships | 21% |
| 2.0 | Manage Internal Relationships | 29% |
| 2.1 | Provide Internal Lobbying Services | 16% |
| 2.2 | Provide Internal Non-Lobbying Services | 2% |
| 2.3 | Provide Other Operational Services | 11% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

# Appendix D: Labor Survey Results by Jurisdiction

## *South Carolina*

| Primary Lobbying Activity Groups | | Breakdown |
|---|---|---|
| 1.0 | Manage External Relationships | 50% |
| 1.1 | Provide Direct Lobbying Services - Federal | 0% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 20% |
| 1.3 | Evaluate and Communicate Strategic Positions | 25% |
| 1.4 | Develop and Maintain Relationships | 5% |
| 2.0 | Manage Internal Relationships | 50% |
| 2.1 | Provide Internal Lobbying Services | 13% |
| 2.2 | Provide Internal Non-Lobbying Services | 7% |
| 2.3 | Provide Other Operational Services | 30% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

## *Florida*

| Primary Lobbying Activity Groups | | Breakdown |
|---|---|---|
| 1.0 | Manage External Relationships | 45% |
| 1.1 | Provide Direct Lobbying Services - Federal | 0% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 28% |
| 1.3 | Evaluate and Communicate Strategic Positions | 12% |
| 1.4 | Develop and Maintain Relationships | 5% |
| 2.0 | Manage Internal Relationships | 55% |
| 2.1 | Provide Internal Lobbying Services | 12% |
| 2.2 | Provide Internal Non-Lobbying Services | 3% |
| 2.3 | Provide Other Operational Services | 40% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

# Appendix D: Labor Survey Results by Jurisdiction

| Federal | | |
|---|---|---|
| | Primary Lobbying Activity Groups | Breakdown |
| 1.0 | Manage External Relationships | 53% |
| 1.1 | Provide Direct Lobbying Services - Federal | 24% |
| 1.2 | Provide Direct Lobbying Services –State and Local | 0% |
| 1.3 | Evaluate and Communicate Strategic Positions | 16% |
| 1.4 | Develop and Maintain Relationships | 12% |
| 2.0 | Manage Internal Relationships | 47% |
| 2.1 | Provide Internal Lobbying Services | 22% |
| 2.2 | Provide Internal Non-Lobbying Services | 16% |
| 2.3 | Provide Other Operational Services | 10% |
| Total Estimated Percentage of Time Spent by Jurisdiction | | 100% |

# Appendix E: Labor Survey Results by Resource

The following table depicts the individual survey results by individual respondent. Most respondents are listed more than once in that they will charge to multiple jurisdictions.

| Jurisdiction | Employee ID # | Responsibility Center | Business Unit's Utility | Survey AC 426 | Survey AC 920 | Survey Other | Comments / Notes |
|---|---|---|---|---|---|---|---|
| Kentucky | 010565 | State President OH/KY Staff | Kentucky - Elect. | 52% | 17% | | Account split between KY - ELE and GAS is 80/20 per validated survey |
| Kentucky | 010565 | State President OH/KY Staff | Kentucky - Gas | 13% | 4% | | |
| Kentucky | 010565 | State President OH/KY Staff | Kentucky - Elect. | | | 1% | Economic Development activities split between KY - ELE and GAS is 67/33 |
| Kentucky | 010565 | State President OH/KY Staff | Kentucky - Gas | | | 1% | |
| Ohio | 010565 | State President OH/KY Staff | Ohio - Gas | | | 2% | Economic Development activities split between OH - ELE and GAS is 80/20 per Survey |
| Ohio | 010565 | State President OH/KY Staff | Ohio - Elect. | | | 10% | |
| Indiana | 015201 | Government Affairs - IN | Indiana | 45% | 55% | | Direct from Validated Survey |
| Kentucky | 018749 | State President OH/KY Staff | Kentucky - Elect. | 9% | 4% | | Jurisdictional split 64% for KY- ELE and GAS per prior fixed distribution |
| Kentucky | 018749 | State President OH/KY Staff | Kentucky - Gas | 5% | 2% | | |
| Ohio | 018749 | State President OH/KY Staff | Ohio - Gas | 21% | 9% | | Jurisdictional split 37/63 for OH - GAS and ELE per prior fixed distribution |
| Ohio | 018749 | State President OH/KY Staff | Ohio - Elect. | 35% | 15% | | |
| Federal | 025421 | Federal Policy & Gov Affairs | DEBS - FED | | 100% | | Direct from Validated Survey |
| Ohio | 026641 | Govt & Community Affairs Ohio | Ohio - Gas | 35% | 15% | | Respondent survey showed OHIO "All" in addition to time spent between electric and gas. KPMG reallocated "ALL" 50/50 to the ELE and GAS jursidiction based on the level of direct charges rates. |
| Ohio | 026641 | Govt & Community Affairs Ohio | Ohio - Elect. | 35% | 15% | | |
| Federal | 034688 | Governmental Affairs - Federal | DEBS - FED | 70% | 30% | | Direct from Validated Survey |
| Federal | 048625 | Rates & Reg Strategy-OH/KY | DEBS - FED | | 20% | | Direct from Validated Survey |
| Kentucky | 048625 | Rates & Reg Strategy-OH/KY | DEBS - KY ELE | | 32% | | Account 920 jurisdictional split between KY - ELE and GAS is 80/20 per Survey Validation |
| Kentucky | 048625 | Rates & Reg Strategy-OH/KY | DEBS - KY GAS | | 8% | | |
| Ohio | 048625 | Rates & Reg Strategy-OH/KY | DEBS - OH ELE | | 25% | | Account 920 spllits based on direct survey results from respondent surveys representing a 63% / 37% split for OH ELE and OH GAS |
| Ohio | 048625 | Rates & Reg Strategy-OH/KY | DEBS - OH Gas | | 15% | | |
| Ohio | 097563 | Govt & Community Affairs Ohio | Ohio - Elect. | 43% | 19% | | Respondent validation noted a 62/38 split between OH - ELE and GAS |
| Ohio | 097563 | Govt & Community Affairs Ohio | Ohio - Gas | 27% | 11% | | |
| Federal | 107880 | Env Affairs & Stakeholder Eng | DEBS - FED | 5% | | | Direct from Validated Survey- Other represents non-lobbying activities |
| South Carolina | 107880 | Environmental Affairs | Carolinas (DEP) | 25% | | | |
| South Carolina | 107880 | Environmental Affairs | Carolinas (DEP) | | | 25% | |
| South Carolina | 107880 | Environmental Affairs | Carolinas (DEC) | 30% | 15% | | |
| South Carolina | 153865 | SC State Gov't Affairs | Carolinas (DEC) | 43% | 8% | | Respondent validation discussions noted a 50/50 Split betweew SC DEC and DEP as the activities performed benefit SC equally. |
| South Carolina | 153865 | SC State Gov't Affairs | Carolinas (DEP) | 43% | 8% | | |
| Ohio | 200252 | State President OH/KY Staff | Ohio - Elect. | 45% | 15% | | Direct from Validated Survey |
| Ohio | 200252 | State President OH/KY Staff | Ohio - Gas | 35% | 5% | | |

# Appendix E: Labor Survey Results by Resource

## Continued

| Jurisdiction | Employee ID # | Responsibility Center | Business Unit's Utility | Survey AC 426 | Survey AC 920 | Survey Other | Comments / Notes |
|---|---|---|---|---|---|---|---|
| Federal | 227322 | Governmental Affairs - Federal | DEBS - FED | | 55% | | Direct from Validated Survey |
| Florida | 227322 | Governmental Affairs - Federal | DEBS - FLA | | 10% | | |
| Indiana | 227322 | Governmental Affairs - Federal | DEBS - IND | | 5% | | |
| Kentucky | 227322 | Governmental Affairs - Federal | DEBS - KY ELE | | 4% | | Account 920 jurisdictional split betw een KY - ELE and GAS is 80/20 per Survey validation |
| Kentucky | 227322 | Governmental Affairs - Federal | DEBS - KYGAS | | 1% | | |
| North Carolina | 227322 | Governmental Affairs - Federal | DEBS - NC DEC | | 5% | | Direct from Validated Survey |
| North Carolina | 227322 | Governmental Affairs - Federal | DEBS - NC DEP | | 5% | | |
| Ohio | 227322 | Governmental Affairs - Federal | DEBS - OH ELE | | 3% | | Account 920 spllits based on direct survey results from respondent surveys representing a 63% / 37% split for OH ELE and OH GAS |
| Ohio | 227322 | Governmental Affairs - Federal | DEBS - OH Gas | | 2% | | |
| South Carolina | 227322 | Governmental Affairs - Federal | DEBS - SC DEC | | 5% | | Direct from Validated Survey |
| South Carolina | 227322 | Governmental Affairs - Federal | DEBS - SC DEP | | 5% | | |
| Federal | 265672 | Governmental Affairs - Federal | DEBS - FED | 70% | 30% | | Direct from Validated Survey |
| North Carolina | 284280 | NC/SC State Gov't Affairs | Carolinas (DEC) | 35% | 15% | | Direct from Validated Survey for DEC and DEP |
| North Carolina | 284280 | NC/SC State Gov't Affairs | Carolinas (DEP) | 35% | 15% | | |
| Florida | 327502 | External Relations | Florida | | 100% | | Direct from Validated Survey |
| North Carolina | 332591 | Environmental Affairs | Carolinas (DEC) | 30% | 20% | | Direct from Validated Survey for DEC and DEP |
| North Carolina | 332591 | Environmental Affairs | Carolinas (DEP) | 30% | 20% | | |
| South Carolina | 338568 | Government Affairs - SC | Carolinas (DEC) | | 100% | | Direct from Validated Survey |
| Florida | 352084 | State President - FL Staff | Florida | 55% | 45% | | Direct from Validated Survey |
| Federal | 354241 | Governmental Affairs - Federal | DEBS - FED | 60% | 40% | | Direct from Validated Survey |
| Florida | 354392 | State President - FL Staff | Florida | 70% | 30% | | Direct from Validated Survey |
| Florida | 358441 | State President - FL Staff | Florida | 90% | 10% | | Direct from Validated Survey |
| Florida | 358442 | External Relations | Florida | 15% | 85% | | Direct from Validated Survey |
| Indiana | 359638 | Indiana President Staff | Indiana | 50% | 50% | | Direct from Validated Survey |
| Federal | 364786 | Governmental Affairs - Federal | DEBS - FED | 50% | 50% | | Direct from Validated Survey |
| North Carolina | 365161 | NC/SC State Gov't Affairs | Carolinas (DEC) | 43% | 8% | | Direct from Validated Survey for DEC and DEP |
| North Carolina | 365161 | NC/SC State Gov't Affairs | Carolinas (DEP) | 43% | 8% | | |
| Indiana | 365544 | Government Affairs - IN | Indiana | 50% | 50% | | Direct from Validated Survey |
| Federal | 367150 | Governmental Affairs - Federal | DEBS - FED | 50% | 50% | | Direct from Validated Survey |
| North Carolina | 442750 | NC/SC State Gov't Affairs | Carolinas (DEC) | 38% | 13% | | Validated Survey noted a 50/50 split betw een DEC and DEP |
| North Carolina | 442750 | NC/SC State Gov't Affairs | Carolinas (DEP) | 38% | 13% | | |
| Federal | 443371 | Governmental Affairs - Federal | DEBS - FED | 75% | 25% | | Direct from Validated Survey |
| Federal | 448281 | Governmental Affairs - Federal | DEBS - FED | 60% | 40% | | Direct from Validated Survey |
| Federal | 451589 | Governmental Affairs - Federal | DEBS - FED | 75% | 25% | | Direct from Validated Survey |

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**Angers Supplemental Exhibit 2**


**Duke Energy Progress, LLC**
**Docket No. E-2, Sub 1219**
**Cash Working Capital for NC Retail Operations - Lead Lag Summary**
**For the test period ended December 31, 2018**
**Summer CP Demand Allocation with MINIMUM SYSTEM**

| Line No. | Description | NC Retail Jurisdictional Amount | Lead \Lag Days | Weighted Amount |
|---|---|---|---|---|
| | | [A] | [B] | [C] |
| | **Calculation of NC Retail Amount:** | | | |
| 1 | Total Revenue Lag | (3,657,503,448) | 42.13 | (154,105,864,564) |
| 2 | Operation and Maintenance Expense | 2,091,224,112 | 33.30 | 69,630,311,534 |
| 3 | Depreciation and Amortization | 669,787,484 | 0.00 | 0 |
| 4 | Taxes Other Than Income Taxes | 102,197,044 | 132.70 | 13,561,920,134 |
| 5 | Interest on Customer Deposits | 7,970,989 | 137.50 | 1,096,011,021 |
| 6 | Income Taxes | 112,986,202 | (20.60) | (2,327,336,581) |
| 7 | Investment of Tax Credit | (2,133,914) | 0.00 | 0 |
| 8 | Net Operating Income | 675,471,531 | 27.48 | 18,562,553,881 |
| 9 | Total Requirements (Sum L3 through L9) | 3,657,503,448 | 27.48 | 100,523,459,988 |
| 10 | Revenue Lag Days (L1) | | 42.13 | |
| 11 | Requirement Lead Days (L9) | | 27.48 | |
| 12 | Net Lag Days (L10 + L11) | | 14.65 | |
| 13 | Daily Requirements (Line 9, Column A divided by 365) | | | 10,020,557 |
| 14 | Cash Working Capital Requirements (L12 x L13) | | | 146,801,108 |
| 15 | Add: Cash Working Capital Related to NC Sales Tax | | | 4,759,823 |
| 16 | Total Cash Working Capital Requirements for NC Retail (L14 + L15) | | | 151,560,932 |
| 17 | **Calculation of Total Company and Jurisdictional Amounts:** | | | |
| 18 | NC Retail: Cash Working Capital allocated at NB_PLT Factor | | | 67.0949% |
| 19 | Total Company Cash Working Capital Requirements (L16 / L18) | | | $ 225,890,470 |

# Duke Energy Progress, LLC

## Lead Lag Study

## March 11, 2020

Building a better
working world

Ernst & Young LLP
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Charlotte, NC 28202

Tel: +1 704 372 6300
ey.com

March 11, 2020

Abbe Greenfield
Rate Case Planning & Execution, Duke Energy Progress, LLC
526 South Church Street
Charlotte, NC 28202

Mrs. Greenfield:

We have completed our procedures with respect to analyzing a detailed lead lag study for Duke Energy Progress, LLC (“the Company” or “DEP”) focused on retail operations in the state of North Carolina. Our procedures were performed in accordance with our Statement of Work, dated April 19, 2018. Our report consists of three parts. We summarize our scope, approach, and findings in a narrative executive summary. We present our detailed findings in a schedule that provides the lag and lead days by revenue and expense component used by DEP in its cost of service filings; and we include an appendix that provides the Company’s summary calculations.

The information provided in this report is intended to be used to support the Company's request for a Cash Working Capital allowance to be included in the Company's requested rate base to be authorized by the North Carolina Utility Commission. The report is not intended to be, and should not be, used without our prior written consent by any other party or for any other purpose. Our calculations relied on underlying accounting information provided by the Company. We did not audit that underlying accounting information.

We value the opportunity to work with you and appreciate the cooperation and assistance provided. We would be pleased to discuss any aspect of our work or this report with you or other members of management at your convenience. If you have questions, please call Jake Van Reen at (617) 375-2446.

Thank you,

Jake Van Reen

# Table of Contents

# Executive Summary

## 1.1. Organization of Report

This report is composed of three parts: Executive Summary, Detailed Findings, and Appendix.

The Executive Summary provides background on the engagement, the purpose and scope of the lead lag study, the standards applied and the relation to previous studies, and a discussion of key findings.

The Detailed Findings are provided in a DEP Lead Lag Summary schedule contained within E-1 Item 14. This schedule provides the lag and lead days by revenue and expense component used by the Company in its cost of service filings. The summary was agreed to the underlying supporting schedules.

## 1.2. Background

Duke Energy (“Duke”) engaged Ernst & Young (“EY”) to support the preparation of a lead lag study for Duke’s retail operations in the state of North Carolina. The study will be used to support the Company’s request for a Cash Working Capital allowance to be included in the requested rate base. This report presents the methodology and approach used in the study and the results covering the twelve-month period ending December 31, 2017, subject to known changes.

The Company last presented a lead lag study to the North Carolina Utility Commission (“NCUC” or the “Commission”) for the twelve-month period ending December 31, 2010. This report presents the lead lag study in the same general format and applies the same methodologies where applicable. Since that time, there are assumed to have been no significant changes in the operating and regulatory environments that would materially affect the calculation of the Cash Working Capital requirements. To confirm this assumption, EY interviewed Duke personnel and a contractor responsible for compiling the study. EY also compared certain of the Company’s financial statements and riders to DEP’s regulatory requirements for the same purpose.

1.3. Changes from report dated July 22, 2019 and filed on October 30, 2019

Total Cash Working Capital Requirements decreased by $7.4M as compared to the previously filed report.

Cash Working Capital Requirements decreased due to the following adjustments:

- Payroll deductions and payroll taxes – Within payroll deductions and payroll taxes, amounts related to incentive compensation were identified. The service period related to these amounts was adjusted to correspond to the service period for incentive compensation. Adjustments to payroll deductions result in a ($5.4M) decrease, while adjustments to payroll taxes result in a ($2.5M) decrease.

Cash Working Capital Requirements increased due to the following adjustments:

- O&M Fuel expense – The company updated the contract allocation percentages for coal delivery contracts, updating the weighting applied to different contract payment terms. This adjustment results in a $275K increase.
- Regulatory commission expense – Regulatory commission expense related to the South Carolina PSC was included in the original study. Removing this item resulted in a $149K increase.
- Pension and benefits – For account 1B410 (Undergrad Tuition Reimbursement), the payment date was adjusted for a January payment. This adjustment results in a $42K increase.

1.4. Cash Working Capital

1.4.1. Purpose of lead lag study

The lead lag study is designed to measure the average amount of capital, over and above the investments in plant, and other separately identified rate base items, provided by investors, to bridge the gap between the time expenditures are required to provide service and the time collections of revenues are received for the service. This quantity is referred to as Cash Working Capital. Cash Working Capital is more comprehensive than simply financing the lag between Company payments and receipts, as investor capital is required to finance the lag in the recovery of the entire cost of service, including depreciation and cost of capital.

1.4.2. Cash Working Capital requirement

A requirement for Cash Working Capital represents the amount necessary to provide the utility with an opportunity to appropriately earn an authorized return on all capital invested in utility operations. Unless all capital supplied by investors has that opportunity, investors will not be fully compensated for the capital supplied and the objective of the Cash Working Capital requirement will not be met. Consequently, the key test of the adequacy of the Cash Working Capital requirement should be whether the inclusion of such an amount, when added to net utility plant and other items includible in the rate base, will produce a fair representation of the capital on which there should be an opportunity to earn a return.

1.4.3. Lead lag study methodology

To the extent applicable, this study tracks the methodology used in the previous rate filings of the Company and decisions of the NCUC.

The lead lag study measures the difference in time frames between: (1) when service is rendered and the revenue for that service is received ("revenue lag"); and (2) when the costs of providing service are incurred (including costs of fuel and purchased power, labor, materials, services, etc.) and the time for which those costs are paid ("expense lead"). The difference between these lag periods is expressed in terms of days. The calculated number of days, multiplied by the average daily operating revenues or cost of service, produces the Cash Working Capital required by the Company.

To fully identify Cash Working Capital requirements, there are additions and deductions to the amount calculated in the lead lag study. This is done to adjust for items not accounted for in rate base. For example, we must add operational cash requirements and add or deduct any other requirements for, or sources of, Cash Working Capital (such as prepayments, reserves, and items capitalized prior to payment). In previous rate case proceedings, these adjustments have been considered separately from the lead lag study, so they are not considered in this report.

1.4.4. Results of lead lag study for DEP retail electric operations

The following section provides a summary of the most significant revenue lags and expense leads calculated. Additional detailed identification of the calculated revenue lags and expense leads is included in the attached schedule entitled E-1 Item 14 (“the summary schedule”).

1.5. Revenue Lag

The revenue lag measures the time between service delivery to customers and the collection of revenue for service from customers. For the year ending December 31, 2017, the majority of North Carolina retail jurisdictional revenue was received from cycle billed customers (customers billed on a periodic basis) and the large customer billing groups.

The revenue lag for these services is the sum of three components: (i) service lag, (ii) billing lag and (iii) collection lag.

The first component is service lag. The Company reads the meters on a monthly basis; therefore the average time between meter reads is 30.42 days (365 days in a year divided by 12 monthly meter reads). Dividing by two provides the midpoint in time, or the average time between when service is provided and the meter read, for a service lag of 15.21 days. (See summary schedule line 4.)

The second component of the total revenue lag is billing lag, the time from the meter reading to when the customer is billed and the bill is posted in the Company’s accounts receivable system. Most customers are billed the next business day after the meter reading. Taking into account weekends and holidays, the calculation of the total billing lag is 1.66 days. (See summary schedule line 6.) This amount differs from the previous study, which deemed the billing lag to be at approximately half a day, as the previous study did not account for weekends and holidays.

The third component of the total revenue lag is the collection lag, the period from the billing date to the time the customer pays their bill (i.e., the date cash payments are credited on the accounts receivable records). This component of the revenue lag is measured by dividing average daily accounts receivable (based on a thirteen-month average) by average daily sales. Collection policies for retail operations in North Carolina are governed by NCUC rules. We calculated the collection lag to be 25.01 days. (See summary schedule line 10.)

Adding these three components together produced a total lag of 41.88 days in the collection of revenues for services provided to cycle-read and large customer billing group customers on electric delivery rate schedules. (See summary schedule line 12.)

EY did not factor in the potential impact of float. The Company experiences two float periods - the time from when funds are received from customers until the funds clear the banks, and the time between when the Company sends a check to pay for services and when those checks are deposited. In the first instance, the Company's cash requirements are increased by the float (i.e. funds are not actually available until after the deposits clear). However, in the second instance, the Company's cash requirements are reduced by the float. Given the relative levels of electronic funds transfers in the Company's payments versus in its receipts, we are confident that the float for revenue is larger than the float for expense. Accordingly, excluding float in this instance is a conservative assumption that would not harm the ratepayer.

In addition to the above, the Company records a variety of additional and miscellaneous revenues which are also applicable to the North Carolina retail jurisdiction. These include intersystem sales for resale, forfeited discounts, rental income, and other electric revenue. To calculate the overall average revenue lag, we calculated the revenue lags for each of the additional and miscellaneous revenues. The total revenue lag for DEP is 42.33 days. (See summary schedule line 38.)

1.6. Expense lead

There are several major categories of expense including:

- O&M Fuel
- O&M Purchased Power
- Other Specifically Identified O&M
- Other O&M Sampled
- Depreciation and Amortization
- Taxes other than Income
- Interest on Customer Deposits
- Income Taxes
- Net Operating Income

- Cash Working Capital impacts of Pass Through items

Each of the above are described in more detail below.

### 1.6.1. O&M Fuel

O&M Fuel costs consist of coal, oil, and natural gas purchases. Fuel is the largest cost category, accounting for approximately 23% of the cost of service for the year ending December 31, 2017. Coal includes two major cost components: coal commodity purchases and coal transportation costs. The cost of coal purchases and transportation are inventoried and, by NCUC precedent, coal fuel inventories are included in rate base. However, the Cash Working Capital requirement must recognize the cash available to the Company stemming from the time between receipt of coal and the subsequent payment of the fuel or transportation invoice.

DEP receives thousands of coal deliveries at its coal generating stations each year. DEP employs the following coal payment terms: (i) contract deliveries made between the 1st and 15th of the current month are paid by the 30th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days); (ii) contract deliveries made between the 1st and 15th of the current month are paid by the 25th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 10th of the following month (17.5 days); (iii) contract deliveries made between the 1st and 31st of the current month are paid by the 30th of the following month (45 days); (iv) contract deliveries made between the 1st and 15th of the current month are paid by the 10th of the following month or contract deliveries made between the 16th and 31st of the current month are paid by the 25th of the following month (32.5 days); and (v) contract deliveries paid 10 days after ship date (10 days). Vendor contracts require DEP payments to be received by the noted due date.

DEP employs the following vendor coal transportation contract terms: (i) coal freight payments 15 days after the ship date (15 days); (ii) coal freight received between the 1st and 15th of the current month are paid by the 30th of the current month or coal freight received between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days).

A small amount of oil is also used as a fuel for generation. Natural gas made up a large portion of the generation fuel. Unlike coal or oil, natural gas is not stored and inventoried, rather it is purchased as it is used to generate electricity. Therefore, the expense lag for natural gas is computed conventionally as the difference between the service period and the date of payment. Since Duke is not storing natural gas to be used for generation, the service period is considered to be the mid-point of the billing period from the gas supplier, and the payment date is simply the date of payment.

The O&M Fuel expense lead for coal, oil and natural gas is 28.49 days. (See summary schedule line 44.)

1.6.2. O&M Purchased Power

DEP provided a listing of all transactions for each Purchased Power account. We weighted the individual invoices by dollar amount, resulting in an overall expense lead of 68.18 days. (See summary schedule line 51.)

1.6.3. Other Specifically Identified O&M

Other specifically identified O&M categories include the following accounts:

- O&M Labor and Benefits
- Uncollectible Accounts
- Regulatory expenses
- Nuclear Fees
- Property Insurance expenses

Labor and Benefits comprised approximately 11% of the cost of service for the year ending December 31, 2017. Labor costs fall into three categories: net payroll, deductions from payroll, and taxes. In turn, the Company's payroll consists of two primary categories, semi-monthly payroll and bi-weekly payroll, with lesser amounts of incentive pay. We identified each pay period and the payment dates corresponding to that pay period. Similarly, for payroll related deductions we identified when the payments were made for each deduction type corresponding to each pay period, including identifying the deductions related to incentive compensation. We performed similar analyses on taxes, looking at pay periods the taxes applied to and when the tax payments were made, including identifying the taxes related to incentive compensation.

Uncollectible Accounts expenses result from the timing of the write-off of customer accounts receivable as uncollectible. By NCUC practice, these expenses are valued at zero days expense lead. (See summary schedule line 57.)

We calculated expense lead days for Regulatory, Nuclear Fees, and Insurance expenses by analyzing service periods, payment amounts and payment patterns. By its nature, Regulatory expense is a quarterly or annual expense and tends to have a longer lead period. For the twelve months ending December 31, 2017, the expense lead for Regulatory Commission expense was 93.25 days. (See summary schedule line 63.) Nuclear fees have a calculated expense lead of (34.66) days. (See summary schedule line 59.)

Property Insurance expenses are payments for policies. By their nature, insurance policies are paid prior to the service period for coverage and have a negative expense lead. For the twelve months ending December 31, 2017, the expense lead for Property Insurance was (222.30) days. (See summary schedule line 65.)

1.6.4. Other O&M Sampled

To determine the expense lead for Other O&M not specifically analyzed (summary schedule line 69), the Company provided EY with a listing of cash disbursements for the twelve-month period ending December 31, 2017. We removed records for capital costs, non-electric O&M costs, and any costs already analyzed, resulting in a sample population consisting of $497,471,687 and 22,967 rolled vouchers. (Note: there were over 214,000 records, but multiple disbursements were made on the same voucher; since the voucher was the unit sampled, the records were rolled up to the voucher level). From that population, a stratified random sample in nine strata, based on the invoice dollar amount, was selected (260 total selections) for sample testing. For each item sampled, the supporting documentation was obtained and analyzed. For purposes of the analysis, service period information was either provided by Duke based on the supporting documentation or, in instances where the service period was not available, the invoice date was provided. The paid dates utilized in the analysis were taken from the Company’s payables ledger.

The estimated weighted average expense lead calculated from the sample was 44.01 days, plus or minus 4.96 days with 90% confidence. This contrasts to the 32.65 days calculated for the

Other O&M sample from the previous lead lag study. When asked about the increase in days, the client informed us that Duke has 45-day payment terms, and has been following these more closely than previously. EY used statisticians to sample the Other O&M population.

In addition, approximately 1% of the Other O&M costs are employee expenses. These were included in our sample, and we calculated the average lead lag days based on the credit card payment dates. All credit cards have the same monthly service period and payment date. As a result, these were not sampled. Rather the expense lead was calculated as the average time from the midpoint of the service period to the payment date.

### 1.6.5. Depreciation and Amortization

Expenses for Depreciation and Amortization are the result of prior cash transactions that are not initially charged to expense. A zero lag is applied because the expense is deducted from rate base when the expense is recorded. By way of example, investors supply cash for capital investments such as plant assets. A cash transaction occurs when a plant asset is acquired. The plant asset is included in rate base and the cash investment earns a return until depreciation expense is recorded. When depreciation expense is recorded, the amount of the expense is removed from rate base and the expense becomes recoverable in cost of service. However, the cash is not recovered until revenues are collected (e.g., after the revenue lag). Thus, depreciation expense is included in the lead lag study with a zero expense lead to provide a return for the period from when the depreciation expense is booked and removed from rate base until it is recovered from revenues. (See summary schedule line 75.)

### 1.6.6. Taxes other than Income

Expense leads for Taxes other than Income Taxes consider the timing between tax assessments, and the related service period. Some taxes are paid after a significant portion of the service period has occurred. Overall the average expense lead for Taxes other than Income for the period ending December 31, 2017 was 129.46 days. (See summary schedule line 84.) Per the 2010 lead lag study, the average expense lead on Taxes other than Income was 62.90. The increase in the number of days is largely the result of a tax reform occurring in 2014, which had a considerable impact on Privilege or Franchise Tax. These taxes were previously paid shortly after the service period. This rapid payment had previously offset the impact of property taxes, which are paid nearly a year after the service period begins.

1.6.7. Interest on Customer Deposits

Interest is credited to customers who are required to maintain deposits, and the interest is paid either when the deposit is returned or at periodic intervals. The expense lead on customer deposits is 137.50 days. (See summary schedule line 86.)

1.6.8. Income Taxes

Income Taxes have two major components, current and deferred Income Taxes. In turn, current Income Taxes include taxes for the current year and prior periods. The expense lead for current Income Taxes is the result of the statutory payment dates. Similar to the rationale for depreciation expense, the deferred tax expense lead is zero days because net deferred tax liabilities are deducted from rate base when the expense is recorded. The expense lead on Net Income Taxes is (11.49) days. (See summary schedule line 91.)

1.6.9. Net Operating Income

Net Operating Income is the return on invested capital, just as depreciation expense is a return on invested capital. Like depreciation expense, a zero lag was assigned to Net Operating Income in recognition of the fact that the return is earned when the service is provided. (See summary schedule line 99.) Because the return is earned when the service is provided, it would be inappropriate to consider subsequent below the line treatment of Net Operating Income. Therefore, we did not further analyze the subsequent use of Net Operating Income for interest, dividends or reinvestment.

1.6.10. Cash Working Capital impacts of Pass Through items

As noted, to fully identify the Cash Working Capital requirements, to the amount calculated in the lead lag study we must add operational cash requirements and add or deduct any other requirements for or sources of Cash Working Capital. One item the Company has not included elsewhere and is therefore considered here is pass through taxes. Pass through taxes are similar to Taxes other than Income except the payment is due from customers not the Company. The primary pass through tax is the North Carolina utility sales tax. The Company collects these pass through taxes from customers in their bills and pays the tax to the State. The tax is not a Company expense because the Company is merely a conduit of the payments from customers. But, to the extent the Company pays the tax before the funds are received from customers, investors in the Company need to provide the cash to finance the time between payment and recovery. The impact on total DEP Cash Working Capital requirements due to the NC sales pass through tax is $5,841,335. (See summary schedule line 104.)

## Conclusion

We have calculated the revenue lag days and expense lead days documented in the schedule described above. We have also tested the reasonableness of the results based on both a logical review of the revenue and expense items using business operating parameters, and on a comparison to historical results. Based on our analyses, we conclude that these revenue lag days and expense lead days are reasonable and calculated properly.

## Detailed Findings

The revenue lag and expense lead calculations developed in this study are overall quite similar when compared to the 2010 calculations, indicating there have been no significant changes in the operating and regulatory environments that would materially affect the overall calculation of the Cash Working Capital requirements. The calculated overall revenue lag calculated is 42.33 days versus 38.39 days in the prior study, reflecting a reasonably stable revenue lag.

On the expense side there appears to be more variability in the calculated expense leads among individual expense line items. However, the overall expense lead of 22.73 days is consistent with the 20.68 days in the prior study.

Among individual expense items, the expense lead for Taxes other than Income was considerably different. The current study calculated this lead at 129.46 days, versus 62.90 days previously. The increase in the number of lead lag days is largely the result of a 2014 tax reform, which had a significant impact to Privilege or Franchise Tax. These had previously offset the impact of property taxes.

As previously noted, the expense lead for Other O&M not separately analyzed increased to 44.01 days, due to stricter adherence to DEP's 45-day payment terms.

The Cash Working Capital requirement is currently calculated at $179.7 million. When factoring in NC Sales Tax, this amount increases to approximately $185.5 million with rounding, representing a $9.1 million increase from the previous study. This appears to be predominantly driven by a longer revenue lag. The daily requirement decreased from the 2010 study, however the expansion of days for the revenue lag was larger than the expansion of days in the requirement lead. Additionally, pass through items increased tenfold from the previous study. Other Income Taxes had a minimizing effect by expanding the Requirement Lead Days, but the increase in revenue lag and pass through items requires a larger Cash Working Capital Requirement.

Duke Energy Progress, LLC
Cash Working Capital Requirements for NC Retail Operations
Lead Lag Summary
For the Test Year Ended December 31, 2017

| Line No. | | NC Retail Jurisdictional Amount | Lead \Lag Days | Weighted Amount |
|---|---|---|---|---|
| 1 | Total Revenue Lag | (3,347,347,114) | 42.33 | (141,692,605,927) |
| 2 | Operation and Maintenance Expense | 1,828,010,618 | 35.41 | 64,732,835,164 |
| 3 | Depreciation and Amortization | 539,354,933 | 0.00 | 0 |
| 4 | Taxes Other Than Income Taxes | 100,773,052 | 129.46 | 13,046,430,859 |
| 5 | Interest on Customer Deposits | 8,712,804 | 137.50 | 1,198,010,503 |
| 6 | Income Taxes | 250,394,479 | (11.49) | (2,876,315,948) |
| 7 | Investment of Tax Credit | (2,136,868) | 0.00 | 0 |
| 8 | Net Operating Income | 622,238,096 | 0.00 | 0 |
| 9 | Total Requirements | 3,347,347,114 | 22.73 | 76,100,960,578 |
| 10 | Revenue Lag Days | | 42.33 | |
| 11 | Requirement Lead Days | | 22.73 | |
| 12 | Net Lag Days | | 19.60 | |
| 13 | Daily Requirements | | | 9,170,814 |
| 14 | Cash Working Capital Requirements | | | 179,703,138 |
| 15 | Working Capital Related to NC Sales Tax | | | 5,841,335 |
| 16 | Total Cash Working Capital Requirements | | | 185,544,473 |

Duke Energy Progress, LLC
Cash Working Capital Requirements for NC Retail Operations
Lead Lag Summary
For the Test Year Ended December 31, 2017

DE PROGRESS, LLC
INCOME STATEMENT VALUES

| Support Sch # | Line No. | Total Utility Operating Revenue and Expense Line Description | Account | Total YTD Dec 2017 | NC Retail Jurisdictional Amount | Lead \ Lag Days | Weighted Amount |
|---|---|---|---|---|---|---|---|
| | 1 | OPERATING REVENUES: | | | | | |
| | 2 | | | | | | |
| | 3 | | | | | | |
| Calc | 4 | Service Lag | | | | 15.21 | |
| | 5 | Billing Lag | | | | | |
| 1 | 6 | Total Retail Sales & Billing Lag | | (3,664,874,922) | (3,130,222,728) | 1.66 | |
| | 7 | Revenue - REPS | | (43,981,207) | (43,981,207) | | |
| | 8 | Unbilled Revenue | 0440.99, 0442.19, 0442.29, 0444.99, | (17,834,534) | (15,326,966) | | |
| | 9 | | | | | | |
| 2 | 10 | Collection Lag | | | | 25.01 | |
| | 11 | | | | | | |
| | 12 | Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17) | | (3,726,690,663) | (3,189,530,901) | 41.88 | (133,572,238,249) |
| | 13 | | | | | | |
| 3 | 14 | Total Revenue Lag Sales for Resale | | (1,257,931,461) | (98,547,668) | 33.73 | (3,324,012,842) |
| | 15 | Provisions For Rate Refunds | 0449100 | - | - | | |
| | 16 | Total Sales of Electricity (L12 + L14) | | (4,984,622,123) | (3,288,078,569) | 41.63 | (136,896,251,091) |
| | 17 | | | | | | |
| | 18 | Other Revenues: | | | | | |
| | 19 | Forfeited Discounts | 0450100, 0450200 | (8,481,360) | (7,563,655) | 72.30 | (546,852,257) |
| | 20 | Miscellaneous Revenues | 0451100 | (7,667,672) | (6,838,010) | 76.00 | (519,688,760) |
| 4 | 21 | RENT - (454) - DIST PLT REL | | (4,610,121) | (4,022,537) | 41.63 | (167,458,215) |
| | 22 | RENT - (454) - DIST POLE RENTAL REV | | (14,715,792) | (12,301,943) | 182.00 | (2,238,953,626) |
| 4 | 23 | RENT - (454) - TRANS PLT REL | | (676,819) | (404,749) | 41.63 | (16,849,701) |
| | 24 | RENT - (454) - ADD FAC - WHLS | | (3,290,570) | - | 0.00 | - |
| 4 | 25 | RENT - (454) - ADD FAC - RET X LIGHTING | | (6,228,691) | (5,640,043) | 41.63 | (234,794,990) |
| 4 | 26 | RENT - (454) - ADD FAC - LIGHTING | | (4,491,301) | (4,188,657) | 41.63 | (174,373,791) |
| | 27 | RENT - (454) - OTHER | | (7,484,770) | (4,960,817) | 68.21 | (338,385,893) |
| | 28 | OTHER ELEC REV (456) - PROD PLT REL | | (1,957,142) | (1,200,457) | 41.88 | (50,273,138) |
| | 29 | OTHER ELEC REV (456) - TRANS REL | | (10,150,455) | (6,070,143) | 41.88 | (254,207,472) |
| | 30 | OTHER ELEC REV (456) - GEN PLT REL | | - | - | 41.88 | - |
| | 31 | OTHER ELEC REV (456) - WH D/A | | (62,938,028) | - | 41.88 | - |
| | 32 | OTHER ELEC REV (456) - OTHER | | (5,950,637) | (3,944,012) | 41.88 | (165,168,670) |
| | 33 | OTHER ELEC REV (456) - REPS | | (178,392) | (178,392) | 41.88 | (7,470,760) |
| | 34 | OTHER ELEC REV (456) - OTHER ENERGY | | - | - | 41.88 | - |
| | 35 | OTHER ELEC REV (456) - DIST PLT REL | 0456630 | (2,240,720) | (1,955,129) | 41.88 | (81,877,563) |
| 4 | 36 | Total Other Revenues (L19 through L35) | | (141,062,469) | (59,268,545) | 80.93 | (4,796,354,836) |
| | 37 | | | | | | |
| | 38 | Utility Oper Revenues (L17 + L20+ L22 +L24 + L26 + L47 +L49 + L79) | | (5,125,684,592) | (3,347,347,114) | 42.33 | (141,692,605,927) |
| | 39 | ELECTRIC OPERATING REVENUE | | (5,125,684,592) | (3,347,347,114) | | |
| | 40 | | | | | | |
| | 41 | OPERATION AND MAINTENANCE EXPENSE: | | | | | |
| | 42 | | | | | | |
| | 43 | Fuel Used in Electric Generation | | | | | |
| 5 + 6 | 44 | OM Prod Energy - Fuel | | 1,251,419,297 | 762,662,565 | 28.49 | 21,727,022,694 |
| | 45 | | | | | | |
| | 46 | Fuel Used in Elec Gen (HFM Greenbook I/S) | F_FUEL_USED_ELEC_GEN | 1,251,419,297 | 762,662,565 | 28.49 | 21,727,022,694 |
| | 47 | | | | | | |
| | 48 | OM PROD PURCHASES - CAPACITY COST | | 116,417,717 | 71,407,405 | 30.29 | 2,162,930,289 |
| | 49 | OM PROD PURCHASES - ENERGY COST | | 415,529,536 | 252,829,640 | 30.29 | 7,658,209,782 |
| | 50 | OM DEFERRED FUEL EXPENSE | 0557980 | (180,732,923) | (180,189,502) | 0.00 | - |
| 7 | 51 | Purchased Power (Acct 555) + Def Fuel (Acct 557) | 0555XXX | 351,214,330 | 144,047,542 | 68.18 | 9,821,140,071 |
| | 52 | | | | | | |

Duke Energy Progress, LLC
Cash Working Capital Requirements for NC Retail Operations
Lead Lag Summary
For the Test Year Ended December 31, 2017

| Support Sch # | Line No. | Total Utility Operating Revenue and Expense Line Description | Account | Total YTD Dec 2017 | NC Retail Jurisdictional Amount | Lead \ Lag Days | Weighted Amount |
|---|---|---|---|---|---|---|---|
| | 53 | Total Other O&M Excluding Fuel and Purchased Power | | | | | |
| | 54 | | | | | | |
| 9 | 55 | Total Labor Expense | | 562,409,999 | 366,460,746 | 37.07 | 13,584,699,854 |
| | 56 | | | | | | |
| | 57 | Uncollectible Accounts | 0904000, 0904001 | 6,504,470 | 5,800,670 | 0.00 | - |
| | 58 | | | | | | |
| 8 | 59 | Nuclear Fees in Acct 524 | 0524000 | 34,582,782 | 21,212,121 | (34.66) | (735,212,115) |
| | 60 | | | | | | |
| 10 | 61 | Pension and Benefits | 0926XXX | 90,966,042 | 59,272,566 | 13.97 | 828,037,741 |
| | 62 | | | | | | |
| 11 | 63 | Regulatory Commission Expense | 0928000 | 7,127,626 | 5,592,954 | 93.25 | 521,542,961 |
| | 64 | | | | | | |
| 15 | 65 | Property Insurance | 0924XXX | 7,696,581 | 5,184,875 | (222.30) | (1,152,597,643) |
| | 66 | | | | | | |
| | 67 | Injuries & Damages - Workman's Compensation | 0925980 | 288,240 | 194,176 | 0.00 | - |
| | 68 | | | | | | |
| | 69 | Remaining Other Oper & Maint Expense | | 652,535,859 | 457,582,404 | 44.01 | 20,138,201,601 |
| | 70 | | | | | | |
| | 71 | Total O&M Excl. Fuel and Purch. Power | | 1,362,111,599 | 921,300,511 | 36.02 | 33,184,672,399 |
| | 72 | | | | | | |
| | 73 | Total Operation and Maintenance Expense (L46 + L51 + L71) | | 2,964,745,226 | 1,828,010,618 | 35.41 | 64,732,835,164 |
| | 74 | | | | | | |
| | 75 | Total Depreciation & Amortization & Property Loss | | 762,731,492 | 539,354,933 | 0.00 | - |
| | 76 | | | | | | |
| | 77 | Taxes Other Than Income Taxes | | | | | |
| 9 | 78 | Payroll Taxes | | 37,286,697 | 24,282,736 | 48.41 | 1,175,527,229 |
| 13 | 79 | Property Tax | | 95,736,515 | 64,423,155 | 186.50 | 12,014,918,316 |
| | 80 | FED HEAVY VEHICLE USE TAX | | 45,282 | 35,860 | 0.00 | - |
| | 81 | ELECTRIC EXCISE TAX - SC | | 2,436,779 | - | 0.00 | - |
| | 82 | PRIVILEGE TAX | | 16,254,008 | 12,031,302 | (11.97) | (144,014,686) |
| 13 | 83 | PUC LICENSE TAX - SC | | 1,775,775 | - | 0.00 | - |
| | 84 | Taxes Other Than Income Taxes | | 153,535,056 | 100,773,052 | 129.46 | 13,046,430,859 |
| | 85 | | | | | | |
| 16 | 86 | Total Interest on Customer Deposits | | 9,367,221 | 8,712,804 | 137.50 | 1,198,010,503 |
| | 87 | | | | | | |
| 14 | 88 | Federal Income Tax | | (91,946,206) | (66,117,748) | 44.75 | (2,958,769,227) |
| | 89 | State Income Tax | | 2,562,304 | 1,842,531 | 44.75 | 82,453,280 |
| | 90 | Income Tax - Deferred | | 426,155,043 | 314,669,695 | 0.00 | - |
| | 91 | Net Income Taxes | | 336,771,141 | 250,394,479 | (11.49) | (2,876,315,948) |
| | 92 | | | | | | |
| | 93 | Investment of Tax Credit Adj Net | 04114XX | (3,380,372) | (2,136,868) | 0.00 | - |
| | 94 | | | | | | |
| | 95 | Total Utility Operating Expenses (L73 + L75 + L84 + L86 + L91 + L93 ) | | 4,223,769,763 | 2,725,109,018 | 27.93 | 76,100,960,578 |
| | 96 | | | | | | |
| | 97 | Interest Expense for Electric Operations | | 281,071,586 | 186,290,919 | 0.00 | - |
| | 98 | Income for Equity Return (L99 - L97) | | 620,843,243 | 435,947,177 | 0.00 | - |
| | 99 | Net Operating Income | | 901,914,829 | 622,238,096 | 0.00 | - |
| | 100 | | | | | | |
| | 101 | Total Requirements (Ln 269+273) | | 5,125,684,592 | 3,347,347,114 | 22.73 | 76,100,960,578 |
| | 102 | | | | | | |
| | 103 | | | | | | |
| | 104 | Cash Working Capital Related to NC Sales Tax | | 5,841,335 | | | |

Geosyntec consultants

**RUDOLPH BONAPARTE**

**geotechnical engineering**
**geoenvironmental engineering**
**CCR unit design/permitting/closure**
**MSW/IW/HW/LLRW facility design/permitting**
**natural hazard assessment/mitigation**
**soil, sediment, and groundwater remediation**

## EDUCATION

University of California, Berkeley: Ph.D., Geotechnical Engineering, 1982
University of California, Berkeley: M.S., Geotechnical Engineering, 1978
University of Texas at Austin: B.S., Civil Engineering, 1977

## PROFESSIONAL REGISTRATION

Alabama P.E. Number 17793
Arkansas P.E. Number 9175
California P.E. Number 047076
Colorado P.E. Number 27485
Florida P.E. Number 0052202
Georgia P.E. Number 17516
Illinois P.E. Number 054352
Kansas P.E. Number 17542
Maryland P.E. Number 18232
Michigan P.E. Number 47814
Missouri P.E. Number 298461
New Jersey P.E. Number GE44827
New York P.E. Number 067675
North Carolina P.E. Number 030150
Ohio P.E. Number 56679
South Carolina P.E. Number 31778
Texas P.E. Number 64329
Virginia P.E. Number 020498
Washington P.E. Number 49626

## AWARDS AND HONORS

Georgia Society of Professional Engineers, Lifetime Achievement in Engineering Award (2019)
American Society of Civil Engineers, Terzaghi Lecture Award (2018)
American Society of Civil Engineers, OPAL Lifetime Achievement Award in Design (2016)
American Society of Civil Engineers, Fellow (2015)
University of California, Berkeley – CEE Academy of Distinguished Alumni, Charter Member, (2012)
Academy of Geo-Professionals (ASCE) – Diplomate, Geotechnical Engineering, by Invitation (2009)
American Academy of Environmental Engineers – Board Certification, by Eminence (2008)
National Academy of Engineering – Elected to Membership (2007)
Georgia Engineering Alliance – Grand Project Award (2007)
University of Texas at Austin – CAEE Academy of Distinguished Alumni (2006)
Georgia Engineering Alliance – Georgia Engineer of the Year (2004)
American Society of Civil Engineers – James R. Croes Medal (2000)
International Geosynthetics Society – IGS Award (1994)

North American Geosynthetics Society – Award of Excellence (1991)
International Geosynthetics Society – Special Finalists Award (1990)
National Science Foundation – Graduate Research Fellow (1977-1980)
University of Texas at Austin, Outstanding Graduate Award (1977)
Academic Honor Societies (Phi Kappa Phi, Tau Beta Pi, Chi Epsilon)

## REPRESENTATIVE EXPERIENCE

### *Geotechnical and Geoenvironmental Engineering*

Dr. Bonaparte has substantial experience in site investigations for building foundations, embankments, landslides and natural slopes, underwater sediments, and waste containment facilities. He also has extensive experience in laboratory testing of soils and in the use of subsurface exploration techniques such as cone penetrometer testing, pressuremeter testing, rock coring, and borehole geophysics. Throughout his career, Dr. Bonaparte has been a leader in the development of geotechnical and geoenvironmental applications of geosynthetics, including geomembranes, geogrids and high-strength geotextiles, and geocomposite drainage layers. He has conducted research and developed testing and design methodologies for these materials related to: allowable stresses and strains, interface friction and shear characteristics, puncture and tearing resistance, flow capacity and filtration characteristics, construction survivability, and aging, degradation, and service life. He is experienced in developing and implementing construction quality assurance and quality control plans for these materials. He is also experienced in developing construction specifications and design details (e.g., connections, geometric transitions, terminations, overlaps, and ballasting). He is knowledgeable in the polymer characteristics of these materials (e.g., HDPE, PVC, polyester, polypropylene), manufacturing/fabrication processes, and field installation methods.

Dr. Bonaparte has substantial expertise and experience in the design, construction, and performance evaluation of earth-retaining structures, particularly mechanically stabilized earth structures. As reflected in his publication list, in the 1980s, he was one of the original developers of design methods for use of geogrids in the construction of steep reinforced-soil slopes, mechanically stabilized earth retaining walls, and the use of geogrids and geotextiles for the repair od landslides. He was also heavily involved in the development of design methods for geogrid-reinforced embankments, levees, roads, and work platforms to be constructed over weak foundations and karst terrains. His design experience includes several large reinforced-soil retaining walls and slopes at a fossil power plant in Ohio, a 100-ft high reinforced-soil buttress for a hillside in southern California, and large reinforced-soil highway embankments in Arizona, Montana, Georgia, Florida, and Arkansas. He was also heavily involved in the investigation and repair of several large landslides in northern and southern California. Repair elements included steel H-piles, rock buttresses, gravel buttresses, reinforced soil buttresses, and drainage features.

Dr. Bonaparte has designed unreinforced and reinforced earthen dikes for sludge and industrial waste containment for projects in Alabama, Georgia, and California. He has also provided engineering services under contracts to the U.S. Army Corps of Engineers and U.S. Federal Highway Administration (FHWA) on projects involving reinforced soil structures. He was a member of the AASHTO/AGC/ARTBA Task Force 27 that authored the widely used design guideline *In Situ Soil Improvement Techniques*. He also co-authored the FHWA geotechnical engineering circular *Earth Retaining Systems* and FHWA research report *Laboratory Characterization of Soil Properties.* Dr. Bonaparte is experienced in earth dam evaluation and design. His experience in this area includes Lake Petit Dam, Blue Ridge Dam, and

Martins Landing Dam in Georgia, Park Dam in Colorado, Pickwick Dam in Tennessee, and Tablachaca Dam in Peru.

During the early 1980s, Dr. Bonaparte was a member of the engineering team that evaluated the seismic risk potential of a proposed state office complex in Anchorage, Alaska. This evaluation involved detailed back-analyses of slope failures which occurred in Anchorage during the 1964 Good Friday earthquake, as well as an evaluation of the probability of a slope failure at the office complex site due to future seismic events. He was also the lead engineer on a project for the U.S. Army Corps of Engineers involving the interpretation of pile load tests and the development of recommendations on pile load capacities for a lock and dam structure in Louisiana. Other geotechnical assignments include: (i) performing and interpreting static and cyclic steel pipe pile load tests in soft clays adjacent to San Francisco Bay; (ii) investigation of the loss of soil support for several cracked, large-diameter underground pressure conduits at the Sacramento Regional Wastewater Treatment Plant in California, and the construction monitoring of a remedial grouting program to re-establish support for the pipes; and (iii) engineering studies and support for emergency repairs at the Tablachaca Dam landslide (13 million cubic meter earth and rock slide) in the Peruvian Andes. With respect to Tablachaca Dam, Dr. Bonaparte led slope stability and construction feasibility studies of various conceptual designs for stabilizing river sediments for construction of an overlying rock stabilization buttress. Conceptual designs that were evaluated included stone columns, displacement piles, vibratory densification, and dynamic compaction. Gravel columns constructed using the Franki method and vibroreplacement method were ultimately selected and implemented to densify and strengthen the river sediments.

Dr. Bonaparte is experienced in the geotechnics of industrial by-product materials, dredged materials, and wastes, including specifically coal-combustion residuals (CCR), chromite ore processing residues (COPR), solvay wastes, ammonia soda ash wastes (ASAW), brine muds, phosphogypsum wastes, sulfate sludges, and municipal solid wastes (MSW).

***Coal Combustion Residual Unit Design and Closure***

Dr. Bonaparte is presently serving as the engineer-of-record and project director for consolidated lined closure of a 250-acre coal combustion residuals (CCR) impoundment in the southeast for a major power utility. The impoundment is being closed to comply with state and federal regulations governing the design, operation, and closure of CCR impoundments. Dr. Bonaparte is also serving as the project director for the consolidated lined closure of CCR impoundments at another site for the same power utility. This second plant location contains four CCR impoundments totaling more than 500 acres cubic yards of CCR. In a third project, Dr. Bonaparte is a subject matter expert and peer reviewer for the consolidated in-place closure for a 340-acre CCR impoundment. Over the past 25 years, Dr. Bonaparte has been involved in additional CCR landfill/impoundment design, construction, closure, and/or assessment projects in Georgia, Tennessee, Virginia, Ohio, Florida, Kentucky, Alabama, and Iowa. He is also co-author of a technical paper related to CCRs titled "Overview of Final Cover Systems for CCR Unit Closures and Major Design Considerations," contained in the proceedings *2017 World of Coal Ash (WOCA) Conference.*

***MSW, IW, HW, and LLRW Facility Design, Permitting, and Performance Evaluation***

Dr. Bonaparte was the project manager and design engineer-of-record for a state-of-the-art low-level radioactive waste (LLRW) disposal facility constructed as part of a CERCLA remedial action at the

Department of Energy (DOE) Fernald Environmental Management Project (FEMP) in Fernald, Ohio. This project included Title I, II and III design services for a 2.5 million cubic yard facility for the long-term disposal of a variety of impacted materials from the demolition and restoration of the Fernald Feed Materials Plant. The scope of work included preparation of design criteria packages (DCPs), plans, specifications, and calculations, soil-liner test pad program, leachate-geomembrane liner compatibility study, soil-geomembrane-GCL interface shear testing program, vegetative cover study, and preparation of support plans including CQA plan, waste placement plan, stormwater management and erosion control plan, O&M plan, and air monitoring plan. The Fernald project was started in 1995 and successfully completed (i.e., construction, filling, and closure of the facility) in 2006. Presently, Dr. Bonaparte is serving as technical director for Title I and II design services for a similar state-of-the-art LLRW disposal facility at the DOE Portsmouth Gaseous Diffusion Plant in Piketon, Ohio.

Dr. Bonaparte is experienced in the siting, design, permitting, construction, and closure of municipal (MSW), industrial (IW), and hazardous waste (HW) landfills and surface impoundments in a variety of geological and hydrogeological settings, including coastal plains, Piedmont deposits, glacial tills, hilly and mountainous topography, karst terrains, former coal and iron ore surface mines, and desert alluvium. He has been involved in the analysis and/or design of projects at sites involving geological hazards, including landslides, ground faulting, seismically induced strong ground motions, sinkholes, and mine works. Dr. Bonaparte has directed, managed, and served as engineer-of-record for many public-sector clients, including Anne Arundel County (Maryland), Town of Babylon (New York), Chester County Solid Waste Authority (Pennsylvania), Delaware Solid Waste Authority (Delaware), Forsyth County (Georgia), Gloucester County (New Jersey), City of High Point (North Carolina), Hudson County (New Jersey), King County (Washington), Los Angeles Sanitation Districts (California), Orange County (California), Riverside County (California), Sonoma County (California), and the U.S. Army Rocky Mountain Arsenal (Denver). He has also managed, directed, or provided engineering review for design projects for many private-sector clients, including Arco Chemical Company, Browning-Ferris Industries, Ciba-Geigy Corporation, City Management Corporation, Energy Solutions, Inc., Honeywell, Inc., Laidlaw, Mine Reclamation Corporation, USA Waste Services, and Waste Management, Inc.

Over a period of more than 20 years, Dr. Bonaparte worked extensively in a contract research capacity for the U.S. Environmental Protection Agency (EPA) in the evaluation of liner and final cover systems for municipal, industrial, and hazardous waste disposal facilities. Through this work, he is today widely regarded as a national leader in the design and performance evaluation of waste containment systems for all types of solid waste landfills in the U.S. and around the world. Starting in the mid-1980s, he and colleagues conducted basic studies under contract to EPA that resulted in the first analytical model for quantifying potential leachate leakage rates through composite liners and double-liner systems being considered by EPA at that time for inclusion in hazardous waste landfill regulations. He and colleagues developed another analytical model for performance evaluation and design of leakage detection layers, and they introduced the concepts of action leakage rate and response action plans that are in wide use today. Dr. Bonaparte was the lead author of two major EPA technical documents in 1987 (see list of publications) that formed the basis for new landfill regulations under the Resource Conservation and Recovery Act (RCRA) that are still in force today. Subsequently, under a later EPA contract, he conducted a seminal nationwide study of the field performance of 187 operating landfill cells. This work was published in a major 2002 EPA report ("*Assessment and Recommendations for Improving the Performance of Waste Containment Systems*") and is today widely used and cited. Under a more recent EPA contract, Dr. Bonaparte led preparation of the draft EPA document "*Technical Guidance for RCRA/CERCLA Final Covers.*" In addition to the foregoing, he is the author/co-author of numerous publications on this topic and he served as Editor of a 1990 ASCE Geotechnical Special Publication No.

26 "*Waste Containment Systems: Construction, Regulation, and Performance*". He was also an invited keynote speaker/author for the 1995 ASCE Specialty Conference and resulting Geotechnical Special Publication No. 46 "*Geoenvironment 2000*". The title of his keynote lecture and paper were "*Long-term Performance of Landfills*".

Through the work described above, Dr. Bonaparte and his colleagues have been at the forefront of the development and validation of design methods for waste containment systems. These include methods to: estimate potential leakage rates through geomembrane, soil, and composite liners; calculate hydraulic heads and flow rates in leachate collection systems and leakage detection systems; calculate action leakage rates; calculate detection times in leakage detection systems; calculate slope stability factors of safety for liner systems and cover systems and for deep-seated waste failures; estimate seismically-induced landfill movements and deformations; design mechanically-stabilized earthen berms integrated into the landfill structure for stability and volume enhancement; design of geosynthetic foundation reinforcement systems to mitigate potential adverse effects of differential foundation systems; and design of geosynthetic foundation reinforcement systems for "piggyback" landfills.

***Contaminated Soil/Sediment/Groundwater Investigation and Remediation***

Dr. Bonaparte has been extensively involved in projects involving remedial investigations and remedial designs for soil, sediment, and groundwater contamination. His project experience includes:

- Project director for remedial design (RD) of the Berry's Creek Study Area (BCSA); the BCSA is a 12-square mile side embayment of the Hackensack River Estuary in Bergen County, New Jersey (the "Meadowlands"); this ongoing project involves design of the EPA Record of Decision (ROD) for the Phase 1 remediation of the study area; the remediation will involve: bank-to-bank dredging of soft sediment within 84-acres of tidal waterways and tributaries; backfilling/capping the dredged areas with clean backfill; removal of Hg-contaminated sediment in a 28-acre marsh (formerly tidal, but now cut off by a tide gate), followed by backfilling and marsh restoration; dewatering and stabilization of the dredged/excavated sediment for off-site disposal; water treatment; a marsh-treatability demonstration project (about 8-acres in size); and a remedy performance monitoring program.

- Project director for remedial investigation and feasibility study (RI/FS) of the BCSA and project manager for the FS; the project, completed in 2018, involved investigation of legacy contamination of waterway sediment, *Phragmites* marshland, surface water, and groundwater; development of a detailed conceptual site model (CSM) for the entire study area; treatability and pilot studies; and, preparation of an FS for interim source control measures for select waterways and marshes;

- project director for remedial design of the Gowanus Canal Superfund site in Brooklyn, New York; the canal is nearly two-miles long, running through the heart of Brooklyn and discharging into Upper New York Bay; heavily contaminated by historical industrial and municipal discharges, a group of PRPs is responsible for the design and implementation of an EPA Record of Decision; Geosyntec is currently performing the remedial design which includes: dredging, treating, and disposing of contaminated sediment; stabilizing in-situ remaining sediment containing DNAPL; installing a multi-layer sediment cap over the remaining sediment after dredging is complete; and stabilizing/rehabilitating bulkheads that line the banks of the canal.

- consultant to industrial client in conceptual development and design of sediment consolidation area (SCA) at Onondaga Lake, New York; SCA will be sited on top of existing 70 ft. thick Solvay waste bed, creating significant geotechnical challenges, and will contain sediments dredged from the lake that are impacted by mercury and other chemicals;

- consultant to industrial client in evaluation of the stability of in-lake waste deposits (ILWD) at Onondaga Lake, New York; project involved evaluation of the geotechnical stability of the ILWD and underlying sediments; related projects involved design of lakefront steel sheet pile subsurface barriers to prevent DNAPL migration into the lake and provide lake bank geotechnical stability in an area designated for dredging;

- principal-in-charge for evaluation and design of permeable reactive barriers (PRBs) for hexavalent chromium impacted groundwater in Hudson County, New Jersey; reactive media evaluated include zero valent iron (ZVI), peat, and organic amendments;

- consultant to Port of Houston Authority (PHA) for the design of soil, sediment, and groundwater remediation measures for property along Green's Bayou, Houston Ship Channel, Texas; contaminants of concern included DDT, DDE, BHC isomers, chlorobenzene, and arsenic; served on core technical team that assisted client in negotiating financial settlement with an adjacent manufacturer of organochlorine pesticides;

- core member of multi-disciplinary client team to develop in-situ and ex-situ treatment technologies for remediating sites containing chromium-containing industrial process slag in New Jersey and Maryland; the slag material contains high hexavalent chromium concentrations (>3,000 mg/kg), high alkalinity (pH>12), and it is expansive; treatment technologies considered include chemical reduction, pH adjustment, stabilization/solidification, and vitrification; led design and oversight of large-scale pilot tests of chemical treatment using pugmills, shallow soil mixing vertical augers, and horizontal rotary mixers;

- principal-in-charge and engineer-of-record for preparation of a focused feasibility study (FFS), ROD amendment, Explanations of Significant Differences (ESD), and remedial design for the Bailey Dump NPL site, Orange, Texas; the project involved removal of tarry sludges and contaminated sediments from tidal marshlands along the Neches River on the Texas/Louisiana border; the project also involved innovative closure of two uncontrolled dumps in the marshland using lightweight RCRA caps and other measures;

- member of external technical review team (focus on in-situ containment and sludge solidification) for the Chevron Port Arthur Refinery remediation project, Port Arthur, Texas;

- consultant to PRP technical committee for negotiation of the Proposed Plan and ROD for the MIG/DeWane NPL site, Belvidere, Illinois;

- technical director for work plan and remediation design development, Yeoman Creek NPL site, Waukegan, Illinois; project involved CERCLA landfill closure, active methane gas extraction system, subsurface barriers, and stream sediment investigation and remediation;

- technical director for remedial design of soft sludge sulfate basins at the Avtex Fibers NPL site, Front Royal, Virginia; design included geotechnical stabilization measures, water management, and capping over the soft sludges;

- principal-in-charge for analysis, conceptual design, and regulatory negotiation for the final cover system for the Operating Industries Inc. (OII) NPL site in Monterey Park, California;

- principal-in-charge for work plan development, preliminary design, and design/build contractor procurement and oversight, Wingate Road NPL Site, Fort Lauderdale, Florida;

- principal-in-charge of site characterization and corrective measures, Eagle No. 2 coal mine site, Shauneetown, Illinois;

- project manager for investigation of groundwater impacts due to treated spent potliner disposal in bauxite mine pit backfill, Bryant, Arkansas;

- project engineer for design of removal actions for the LCP Chemicals NPL site in Brunswick, Georgia;

- technical team member for geotechnical investigation, landslide stabilization design, and remedial design for the Vandale Junkyard NPL site, Marietta, Ohio;

- principal-in-charge of soil and groundwater remedial investigations for CERCLA landfills near Baltimore, Maryland and Mt. Holly, New Jersey;

- project manager for preparation and implementation of a remedial action plan (RAP) for acid-impacted groundwater at a former metal finishing site in Dade County, Florida;

- principal-in-charge and engineer-of-record for design and preparation of construction bid documents for remediation (final cover, subsurface leachate interceptor, and waste slope toe buttress) for a closed municipal/ industrial landfill in Cuyahoga County, Ohio;

- project engineer for investigation of organic solvent contamination of groundwater at three semiconductor manufacturing plants in northern California;

- project engineer for asbestos and asbestos-contaminated soil remediation of a former industrial site in Redwood City, California; and

- project engineer for remedial investigation of an abandoned leather tannery in south San Francisco, California.

## AFFILIATIONS

American Society of Civil Engineers
American Society of Civil Engineers: Geo-Institute
American Society of Civil Engineers: Environmental and Water Resources Institute
Deep Foundations Institute
International Society on Soil Mechanics and Geotechnical Engineering
International Geosynthetics Society
National Ground Water Association
North American Geosynthetics Society

## PROFESSIONAL HISTORY

Geosyntec Consultants, Atlanta, Georgia, Chairman, 2016-date; President & CEO, 1996-2016; Senior Principal, 1988-date; Senior Engineer, 1986-1987
Georgia Institute of Technology, Atlanta, Georgia, Professor of the Practice (part-time), School of Civil & Environmental Engineering, 2016-date
The Tensar Corporation, Morrow, Georgia, Applications Technology Manager, 1984-1986
Woodward-Clyde Consultants, San Francisco, California, Assistant Project Engineer, 1982-1983
University of California, Berkeley, California, National Science Foundation Graduate Research Fellow, 1977-1980

## LITIGTION SUPPORT ACTIVITIES

- The Coakley Landfill Group v. IT Corporation v. Gary Blake, Inc. et al., Civil Action No. 98-CV-167 in the U.S. District Court for the District of New Hampshire.(expert report, deposition, and trial testimony, 2000/2001)

- Browning-Ferris Industries, Inc. et al. v. Certain Underwriters at Lloyd's London, et al., Cause No. 98-56362, in the District Court of Harris County, Texas, 80th Judicial District. (expert report, deposition, trial testimony, 2000-2012 [intermittent])

- Port of Houston Authority vs. G. B. Biosciences et al., Cause No. 2001-07795, in the District Court of Harris County, Texas, 151st Judicial District.(expert report, 2003)

- Waste Management of Georgia, Inc. v. Harold Reheis, Director, Environmental Protection Division, Department of Natural Resources, before the Office of State Administrative Hearings, State of Georgia. (testimony before a state administrative law judge, 2003)

- Friends of the Green Swamp, Petitioner, v. North Carolina Department of Environment and Natural Resources and Division of Water Quality, Respondent, and Riegel Ridge, LLC, Intervenor-Respondent, in the Office of Administrative Hearings, O3 EHR 0058, County of Columbus, State of North Carolina. (qualified as expert by administrative law judge and provided testimony, 2004)

- Interfaith Community Organization, et al., Plaintiffs, v. Honeywell International, Inc., et al., Defendants, Civil No. 95-2907 (DMC), in the U.S. District Court, District of New Jersey. (declaration submitted to the court under Rule 60(b)(5), 2005)

- State of Maryland, Department of Environment, Plaintiffs, v. Honeywell International, Inc. and Maryland Port Administration, Defendants, Civil Action No. 07-CV-00724-MJG, in the U.S. District Court, District of Maryland/Northern Division. (expert report, deposition and trial testimony, 2007/2008)

- Hackensack Riverkeeper, Inc., et al., Plaintiffs, v. Honeywell International, Inc. et al., Defendants, Civil No. 06-22, in the U.S. District Court, District of New Jersey. (expert report, 2008/2009)

- Intalco Aluminum Corporation, Plaintiffs, v. Central National Insurance Company of Omaha, et al., Defendants, Case No. 06-2-01842-3 in The Superior Court of the State of Washington for Whatcom County. (expert report and deposition testimony, 2009/2010)

- Texas Disposal Systems Landfill, Inc., Plaintiffs, v. Waste Management Holdings, Inc., Defendants, Cause No. 97-12163, District Court of Travis County, Texas, 126th District. (expert report, deposition testimony, trial testimony, 2010/2011)

- Hackensack Riverkeeper, Inc., et al., Plaintiffs, v. Honeywell International, Inc. et al., Defendants, Civil No. 06-22, in the U.S. District Court, District of New Jersey. (expert report, 2015)

## SIGNIFICANT INVITED LECTURES, WORKSHOPS, AND COMMITTEES
## RUDOLPH BONAPARTE

86-1 American Society of State Highway and Transportation Officials – AASHTO/AGC/ARTBA Task Force 27 on In-Situ Soil Improvement Techniques (1986 – 1990)

87-1 NATO Advanced Study Institute – "Polymeric Reinforcement in Soil Retaining Structures," Kingston, Canada (1987) (Invited Lecture and Participant)

89-1 American Society of Civil Engineers, New York Metro Annual Geotechnical Lecture Series – Geosynthetic Reinforcement of Embankment Slopes (1989) (Invited Lecture)

90-1 American Society of Civil Engineers – Member, Soil Improvement and Geosynthetics Committee, Geotechnical Engineering Division (1990 – 1993)

90-2 American Society of Civil Engineers, ASCE National Convention, Symposium on "Waste Containment Systems: Construction, Regulation, and Performance," (1990) (Symposium Organizer and Chair)

91-1 American Society of Civil Engineers – Chairman, Session Program Committee, Geotechnical Engineering Division (1991 – 1994)

91-2 National Science Foundation – Workshop on Soil Improvement and Foundation Remediation with Emphasis on Seismic Hazards (1991) (Invited Participant)

92-1 American Society of Civil Engineers – Editorial Board, Journal of Geotechnical Engineering (1991 – 1994)

94-1 National Science Foundation – Workshop on Research Priorities for Seismic Design of Solid Waste Landfills (1994) (Invited Lecture and Participant)

94-2 International Geosynthetics Society – Editorial Board, Geosynthetics International Journal (1994 – present)

95-1 NATO Advanced Study Institute – "Advances in Groundwater Pollution Control and Remediation," Antalya, Turkey (1995) (Invited Lecture and Participant)

95-2 American Society of Civil Engineers – "Long-Term Performance of Landfills," Geoenvironment 2000 Conference (1995) (Invited Keynote Lecture)

00-1 American Society of Civil Engineers – Member, Geo-Institute Awards Committee (2000 – 2002)

01-1 National Research Council – Workshop on Safeguarding the Future: Assessing the Performance of Engineered Containment Systems for Waste Disposal (2001) (Invited Lecture and Participant)

02-1 American Society of Civil Engineers – Geo-Institute Board of Governors (2002)

03-1 U.S. Environmental Protection Agency – Workshop on Bioreactor Landfills (2003) (Invited Lecture and Participant)

06-1 Editorial Board – International Journal of Geoengineering Case Histories (2006 – present)

06-2 University of California, Berkeley – Civil and Environmental Engineering (CEE) Advisory Council (2006 – 2016), Chair (2008-2012)

07-1 University of California, Berkeley – CEE Geoengineering Distinguished Lecture Series (2007) (Invited Lecture)

07-2 National Research Council – Assessment of the Performance of Engineered Waste Containment Barriers - NRC (2007) (Independent Reviewer)

08-1 Global Waste Management Symposium – Technical Committee (2008)

08-2 Virginia Tech – Center for Geotechnical Practice and Research Annual Lecture Program (2008) (Invited Lecture)

08-3 National Research Council – Fourth Report of the Academy of Engineering/National Research Council Committee on New Orleans Regional Hurricane Protection Projects: Review of the IPET Volume III (2008) (Independent Reviewer)

08-4 University of Texas at Austin – Civil, Architectural, and Environmental Engineering (CAEE) External Advisory Committee (2008 – 2012), Chair (2011-2012)

08-5 U.S. Department of Energy – Landfill Technology Development Workshop (2008) (Invited Lecture and Participant)

09-1 National Research Council – Advice on the Department of Energy's Cleanup Technology Roadmap – (2009) (Independent Reviewer)

09-2 National Research Council – The New Orleans Hurricane Protection System, Assessing Pre-Katrina Vulnerability and Improving Mitigation and Preparedness - NRC (2009) (Independent Reviewer)

09-3 St. Martins Episcopal School – Board of Trustees (2009-2016), Vice Chair (2014)

10-1 American Society of Civil Engineers, GeoFlorida Conference – "Research, Teaching, and Practice Interrelationships in Geo-Engineering Development" (2010) (Invited Panel Participant)

11-1 Texas A&M University – Spencer J. Buchanan Annual Distinguished Lecture Program (2011) (Invited Buchanan Lecturer)

11-2 University of Texas at Austin – CAEE Distinguished Young Alumni Committee (2011-2012), Chair (2012)

11-3 National Academy of Engineering – Nominating Committee (2011-2012)

12-1 American Society of Civil Engineers, GeoCongress 2012 Conference – "Demonstrating the Value Geo-Professionals Provide to Projects" (2012) (Invited Panel Participant)

12-2 American Society of Civil Engineers, GeoCongress 2012 Conference – "The Business of Geotechnical and Geoenvironmental Engineering – State of Practice" (2012) (Invited Keynote Lecture)

12-3 University of California, Berkeley, Board Chair, Civil and Environmental Engineering Academy of Distinguished Alumni (2012-2021)

13-1 National Academy of Engineering – Peer Committee, Section 4 (2013-2015)

13-2 National Research Council – Levees and the National Flood Insurance Programs: Improving Policies and Practices – NRC (2013) (Independent Reviewer)

13-3 University of Minnesota, 61st Minnesota Geotechnical Conference (2013) (Invited Keynote Speaker)

14-1 National Research Council – Reducing Coastal Risks on the East and Gulf Coasts – NRC (2014) (Independent Reviewer)

15-1 Stanford University – Invited Lectures, CEE 275K: The Practice of Environmental Consulting and Engineering

15-2 California Geotechnical Engineering Association (CalGeo) Annual Conference (2015) (Invited Keynote Lecture)

15-3 Georgia Institute of Technology – Lead-Instructor, CEE 4000: Global Engineering Leadership and Management (2015-2018)

16-1 Georgia Institute of Technology and ASCE Georgia Section, 19th George F. Sowers Lecturer, George F. Sowers Annual Symposium (2016) (Invited Keynote Lecture)

16-2 American Society of Civil Engineers, Geo-Institute - Nominations and Elections Committee (2016)

16-3 American Society of Civil Engineers, Geo-Chicago 2016 Conference – "The Interface of Professional Practice, Research, and Education" (2016) (Invited Panel Participant)

16-4 American Society of Civil Engineers, Committee on Claims Reduction and Management (2016-2020)

17-1 National Academy of Engineering, Committee on Membership (2017-2020)

18-1 University of California, Davis – Invited Lectures to Geotechnical Graduate Student Society (2018)

18-2 University of Kansas – 50th Annual Geotechnical Engineering Conference (2018) (Keynote Speaker)

18-3 Queens University – 20th Victor Milligan Lecture (2018)

19-1 American Society of Civil Engineers – GeoCarolinas (2019) (Invited Keynote Lecture)

19-2 Virginia Tech – Center for Geotechnical Practice and Research Annual Lecture Program (2019) (Invited Keynote Lecture)

19-3 University of Washington – Robert G. Hennes Memorial Lecture (2019)

19-4 Boston Society of Civil Engineers – Geotechnical Seminar Series (Invited Keynote Lecture)

19-5 University of California, Berkeley – Symposium Honoring James K. Mitchell (2019) (Invited Guest Speaker)

19-6 University of Colorado, Boulder – 27th Jack W. Hilf Lecture (2019)

19-7 Texas A&M University – Spencer J. Buchanan Annual Distinguished Lecture Program (2019) (Invited Guest Lecturer)

19-8 American Society of Civil Engineers – Geo-Institute Awards Committee (2019-2020)

20-1 National Academy of Engineering – Bernard M. Gordon Prize for Innovation and Technology and Evaluation Selection Committee (2020-2022)

## LIST OF PUBLICATIONS
## RUDOLPH BONAPARTE


79-1 Bonaparte, R. and Mitchell, J.K., *Engineering Properties of San Francisco Bay Mud*, Geotechnical Engineering Report, University of California, Berkeley, 1979.

80-1 Bonaparte, R. and Mitchell, J.K., *Evaluation of a General Stress-Deformation-Time Model for Cohesive Soils*, Geotechnical Engineering Report, University of California, Berkeley, 1980.

80-2 Bonaparte, R. and Mitchell, J.K., *Development of Experimental Concepts for Investigating the Strength Behavior of Fine Grained Cohesive Soils in the Spacelab/Space Shuttle Zero-G Environment,* NASA Contract Report 3365, Marshall Space Flight Center, Huntsville, 1980.

80-3 Kavazanjian, E., Mitchell, J.K., and Bonaparte, R., "Stress-Deformation Predictions Using a General Phenomenological Model," *Proceedings of the NSF/NSERC Workshop on Plasticity Theories and Stress-Strain Modeling of Soils*, American Society of Civil Engineers, Montreal, 1980.

81-1 Bonaparte, R. and Mitchell, J.K., *Evaluation of Laboratory Characterization of Cohesive Soils,* Geotechnical Engineering Report, University of California, Berkeley, 1981.

81-2 Bonaparte, R., *A General Time-Dependent Constitutive Model for Cohesive Soils,* submitted in partial fulfillment of the requirements for the degree of Doctor of Philosophy, University of California, Berkeley, 1981.

82-1 Singh, R.D., Bonaparte, R., and Gardner, W.S., *Laboratory Characterization of Soil Properties,* final report, Contract No. DOT-FH-11-9627, Office of Research and Development, Federal Highway Administration, U.S. Department of Transportation, Washington D.C., 1982.

82-2 Bonaparte, R., *Hazardous Waste-Soil Interactions,* report to Woodward-Clyde Consultants, Professional Development Committee, 1982, 54 p.

84-1 Giroud, J.P., Ah-Line, C., and Bonaparte, R., "Design of Unpaved Roads and Trafficked Areas with Geogrids," *Proceedings of the Conference on Polymer Grid Reinforcement*, Institution of Civil Engineers, London, 1984, pp. 116-127.

84-2 Bonaparte, R. and Margason, E., "Repair of Landslides in the San Francisco Bay Area," *Proceedings of the Conference on Polymer Grid Reinforcement*, Institution of Civil Engineers, London, 1984, pp. 64-68.

84-3 Giroud, J.P., and Bonaparte, R., "Waterproofing and Drainage: Geomembranes and Synthetic Drainage Layers," *Proceedings of the Second International Symposium on Plastic and Rubber Waterproofing in Civil Engineering*, Liege, 1984.

84-4 Williams, N., Giroud, J.P., and Bonaparte, R., "Properties of Plastic Nets for Liquid and Gas Drainage Associated with Geomembranes," *Proceedings of the International Conference on Geomembranes*, Denver, 1984, pp. 399-404.

84-5 Margason, E. and Bonaparte, R., "Landslide Repair in Orinda Claystone Utilizing Geogrid Reinforcement," *Proceedings of the International Symposium on Landslides*, Toronto, 1984.

85-1 Bonaparte, R., Williams, N., and Giroud, J.P., "Innovative Leachate Collection Systems for Hazardous Waste Containment Facilities," *Proceedings of Geotechnical Fabrics Conference '85*, IFAI, Cincinnati, 1985, pp. 9-34.

85-2 Bonaparte, R., Giroud, J.P., and Holtz, R.D., "Soil Reinforcement Design Using Geotextiles and Geogrids," published in ASTM Special Technical Publication #952, *Geotextile Testing and the Design Engineer*, 1985, pp. 69-118.

86-1 Berg, R.R., Bonaparte, R., Anderson, R.P., and Chouery, V.C., "Design, Construction and Performance of Two Reinforced Soil Retaining Walls," *Proceedings of the 3rd International Conference on Geotextiles*, Vienna, 1986, pp. 401-406.

86-2 Bonaparte, R., Schmertmann, G.R., and Williams, N., "Seismic Design of Slopes Reinforced with Geogrids and Geotextiles," *Proceedings of the Third International Conference on Geotextiles*, Vienna, 1986, pp. 273-278.

87-1 Bonaparte, R. and Christopher, B.R., "Design and Construction of Reinforced Embankments Over Weak Foundations," *Transportation Research Record* 1153, Transportation Research Board, Washington, DC, 1987, pp. 26-39.

87-2 Bonaparte, R. and Berg, R.R., "Long-Term Allowable Tension for Geosynthetic Reinforcement," *Proceedings of Geosynthetics '87*, New Orleans, 1987, pp. 181-192.

87-3 Schmertmann, G.R., Bonaparte, R., Chouery, V.C., and Johnson, R.J., "Design Charts for Geogrid Reinforced Slopes," *Proceedings of Geosynthetics '87*, New Orleans, 1987, pp. 108-120.

87-4 Bonaparte, R. and Berg, R.R., "The Use of Polymer Geosynthetics to Support Roadways Over Sinkhole Prone Areas," *Proceedings, 2nd Multidisciplinary Conference on Sinkholes and the Environmental Impacts of Karsts*, Orlando, 1987, pp. 437-445.

87-5 Berg, R.R., Larochelle, P., Bonaparte, R., And Tanguay, L., "Gaspe Peninsula Reinforced Soil Seawall - Case History," *Proceedings of the Symposium on Soil Improvement*, ASCE Geotechnical Special Publication No. 12, Atlantic City, 1987, pp. 309-328.

87-6 Bonaparte, R., "Geosynthetic Earth Reinforcement," *Proceedings of the ASCE-PennDOT Seminar on New Technology in Civil Engineering*, Hershey, Pennsylvania, 1987.

87-7 Bonaparte, R. and Schmertmann, G.R., "Reinforcement Extensibility in Reinforced Soil Wall Design," in *Polymeric Reinforcement in Soil Retaining Structures*, NATO Advanced Study Institute Series, Kluwer Academic Publishers, 1987, pp. 409-458.

87-8 USEPA, "Background Document on Bottom Liner Performance in Double-Lined Landfills and Surface Impoundments," EPA/530-SW-87-103, Apr 280 p. (Dr. Bonaparte was the lead author.)

87-9 USEPA, "Background Document: Proposed Liner and Leak Detection Rule," EPA/530-SW-87-015, 1987, 526 p. (Dr. Bonaparte was the lead author.)

88-1 Bonaparte, R., Ah-Line, C., Charron, R., and Tisinger, L., "Survivability and Durability of a Nonwoven Geotextile," *Proceedings of the Symposium on Geosynthetics for Soil Improvement*, ASCE Geotechnical Special Publication No. 18, Nashville, 1988, pp. 68-91.

88-2 Giroud, J.P., Bonaparte, R., Beech, J.F., and Gross, B.A., "Load-Carrying Capacity of a Soil Layer Supported by a Geosynthetic Overlying a Void," *Proceedings, International Symposium on Theory and Practice of Earth Reinforcement*, Kyushu, 1988, pp. 185-190.

89-1 Peggs, I.D., Tisinger, L.G., and Bonaparte, R., "Durability of a Polypropylene Geotextile in an Unpaved Road Structure," *Transportation Research Record* 1248, Washington D.C., Jan 1989 pp. 1-12.

89-2 Bonaparte, R. and Gross, B.A., "Tensar-Geogrid Reinforced Soil Wall," Experimental Project Program, Experimental Project 1, Ground Modifications Techniques, FHWA-EP-90-001-005, Federal Highway Administration, Washington, D.C., 1989, 119 p.

89-3 Bonaparte, R., Giroud, J.P., and Gross, B.A., "Rates of Leakage Through Landfill Liners," *Proceedings of Geosynthetics '89*, Vol. 1, San Diego, 1989, pp. 18-29.

89-4 Giroud, J.P. and Bonaparte, R., "Leakage Through Liners Constructed with Geomembranes. Part I: Geomembrane Liners," *Geotextiles and Geomembranes*, Vol. 8, No. 1, 1989, pp. 27-67.

89-5 Giroud, J.P. and Bonaparte, R., "Leakage Through Liners Constructed with Geomembranes. Part II: Composite Liners," *Geotextiles and Geomembranes*, Vol. 8, No. 2, 1989, pp. 77-111.

89-6 Bonaparte, R., "Geosynthetic Reinforcement of Embankment Slopes," *Proceedings of the ASCE New York Met Section Seminar, Foundations in Difficult Soils-State of Practice*, 1989, 36 p.

89-7 Bonaparte, R., Schmertmann, G.R., Chu, D., and Chouery-Curtis, V.E., "Reinforced Soil Buttress to Stabilize a High Natural Slope," *Proceedings, XIIth International Conference on Soil Mechanics and Foundation Engineering*, Rio de Janeiro, 1989, pp. 1227-1230.

90-1 Giroud, J.P., Bonaparte, R., Beech, J.F., and Gross, B.A., "Design of Soil Layer-Geosynthetic Systems Overlying Voids," *Geotextiles and Geomembranes*, Vol. 9, No. 1, 1991, pp. 11-20.

90-2 Gross, B.A., Bonaparte, R., and Giroud, J.P., "Evaluation of Flow from Landfill Leakage Detection Layers," *Proceedings, Fourth International Conference on Geotextiles*, Vol. 2, The Hague, 1990, pp. 481-486.

90-3 Bonaparte, R. and Swan, R.H., "Geosynthetic Reinforcement of Embankment Slopes," *Proceedings of the 1990 ASCE Chicago Lecture Series, Geosynthetics in Geotechnics,* Chicago, 1990, 20 p.

90-4 Bonaparte, R. and Gross, B.A., "Field Behavior of Double-Liner Systems," *Proceedings of the Symposium on Waste Containment Systems*, ASCE Geotechnical Special Publication No. 26, San Francisco, 1990, pp. 52-83.

90-5 Bonaparte, R., ed., "Waste Containment Systems: Construction, Regulation, and Performance," Proceedings of a Symposium Sponsored by the American Society of Civil Engineers, ASCE Geotechnical Special Publication No. 26, San Francisco, Nov 1990, 266 p.

90-6 Swan, R.H., Bonaparte, R., Bachus, R.C., Rivette, C.A., and Spikula, D.R., "Effect of Soil Compaction Conditions on Geomembrane-Soil Interface Strength," *Geotextiles and Geomembranes*, Vol. 10, No. 5, 1990, pp. 523-530.

90-7 AASHTO/AGC/ARTBA Task Force 27: "In Situ Soil Improvement Techniques," Washington, D.C., 324 p. (Dr. Bonaparte is a coauthor.)

91-1 Bonaparte, R., Fluet, J.E., Jr., Johnson, R., and Chouery-Curtis, V.E., "Application of Geosynthetics to the W. H. Zimmer Generating Station Project," *Proceedings of Geosynthetics '91*, Vol. 2, Atlanta, 1991, pp. 935-950.

92-1 Giroud, J.P., Badu-Tweneboah, K., and Bonaparte, R., "Rate of Leakage Through a Composite Liner Due to Geomembrane Defects," *Geotextiles and Geomembranes*, Vol. 11, No. 1, 1992, pp. 1-28.

92-2 Seed, R.B. and Bonaparte, R., "Seismic Analysis and Design of Lined Waste Fills: Current Practice," *Proceedings of the Specialty Conference on Stability and Performance of Slopes and Embankments*, Vol. 2, ASCE Geotechnical Special Publication No. 31, Berkeley, 1992, pp. 1521-1545.

93-1 Berg, R.R. and Bonaparte, R., "Long-Term Allowable Tensile Stresses for Polyethylene Geomembranes," *Geotextiles and Geomembranes*, Vol. 12, No. 4, 1992, pp. 287-306.

93-2 Giroud, J.P. and Bonaparte, R., "Geosynthetics in Dam Rehabilitation," *Proceedings of the Specialty Conference on Geotechnical Practice in Dam Rehabilitation*, ASCE Geotechnical Special Publication No. 35, 1993, pp. 1043-1074.

93-3 USEPA, "LDCRS Flows from Double-Lined Landfills and Surface Impoundments," EPA/600/SR-93/070, 1993. (Dr. Bonaparte was the lead author.)

93-4 Bonaparte, R. and Gross, B.A., "Impact of Subtitle D Regulations on Leachate Containment Capabilities of Landfill Liner Systems," *Geotechnical News*, Vol. 11, No. 3, 1993, pp. 46-48.

94-1 Snow, M.S., Bonaparte, R., and Kavazanjian, E., Jr., "Geosynthetic Composite Liner for Subtitle D," *Proceedings, Waste Tech '94*, National Solid Waste Management Association, Charleston, 1994.

94-2 Cargill, K.W., Gross, B.A., North, R.B., and Bonaparte, R., "Subsurface Landfill Barriers," report prepared for the U.S. Navy, Naval Facilities Engineering Command, Port Hueneme, Aug 1994, 136 p.

95-1 Bonaparte, R. "Long-Term Performance of Landfills," *Proceedings of the ASCE Specialty Conference Geoenvironment 2000*, ASCE Geotechnical Special Publication No. 46, Vol. 1, 1995, pp. 515-553.

95-2 Luettich, S.M., Bonaparte, R., Coleman, B.A., and Tomlinson, H.M., "Preconstruction Testing of Two Soil Liners," *Proceedings of the ASCE Specialty Conference Geoenvironment 2000*, ASCE Geotechnical Special Publication No. 46, Vol. 1, 1995, pp. 670-687.

95-3 Kavazanjian, E., Matasovic, N., Bonaparte, R., and Schmertmann, G.R., "Evaluation of MSW Properties for Seismic Analysis," *Proceedings of the ASCE Specialty Conference Geoenvironment 2000*, ASCE Geotechnical Special Publication No. 46, Vol. 2, 1995, pp. 1126-1141.

95-4 Bonaparte, R. and Othman, M.A., "Characteristics of Modern MSW Landfill Performance," *Geotechnical News*, Vol. 13, No. 1, 1995, pp. 25-30.

95-5 Steinhauser, E.S., O'Neill, T.F., and Bonaparte, R., "Increased Disposal Capacity through Landfill Overfilling," *International Landfill Symposium*, Sardinia, Italy, Vol. 1, October 1995, pp. 793-806.

95-6 Giroud, J.P., Bonaparte, R., and Sembenelli, P., "Selection of Waste Containment Systems in Developing Countries," *International Landfill Symposium*, Sardinia, Italy, Vol. 2, October 1995, pp. 149-157.

95-7 Othman, M.A., Bonaparte, R., Gross, B.A., and Schmertmann, G.R., "Design of MSW Landfill Final Cover Systems," *Proceedings of the Symposium on Landfill Closures-Environmental Protection and Land Recovery*, ASCE Geotechnical Special Publication No. 46, 1995, pp. 218-257.

95-8 Kavazanjian, E. Jr., Bonaparte, R., Johnson, G.W., Martin, G.R., and Matasovic, N., "Hazard Analysis for a Large Regional Landfill," *Proceedings of a Symposium on Earthquake Design and Performance of Solid Waste Landfills*, ASCE Geotechnical Special Publication No. 54, 1995, pp. 119-141.

95-9 Giroud, J.P., Bachus, R.C., and Bonaparte, R., "Influence of Water Flow on the Stability of Geosynthetic-Soil Layered Systems on Slopes," *Geosynthetics International*, Vol. 2, No. 6, 1995, pp. 1149-1180.

96-1 Bonaparte, R. and Giroud, J.P., "Waste Containment Systems for Pollution Control: Part II-Hydraulic Design and Performance," Proceedings, NATO Advanced Study Institute Series, *Recent Advances in Ground-Water Pollution Control and Remediation*, Kluwer Academic Publishers, The Netherlands, 1996, pp. 437-478.

96-2 Othman, M.A., Bonaparte, R., and Gross, B.A., "Preliminary Results of Study of Composite Liner Field Performance," *Proceedings of the 10th Geosynthetic Research Institute (GRI) Conference*, Drexel University, Philadelphia, December 1996, pp. 110-137.

96-3 Koerner, R.M., Carson, D.A., Daniel, D.E., and Bonaparte, R., "Current Status of the Cincinnati GCL Test Plots," *Proceedings of the 10th Geosynthetic Research Institute (GRI) Conference*, Drexel University, Philadelphia, December 1996, pp. 147-175.

96-4 Bonaparte, R., Othman, M.A., Rad, N.S., Swan, R.H., and Vander Linde, D.L., "Evaluation of Various Aspects of GCL Performance," Appendix F in *Report of 1995 Workshop on Geosynthetic Clay Liners*, D.E. Daniel and H.B. Scranton authors, EPA/600/R-96/149, USEPA National Risk Management Research Laboratory, Cincinnati, 1996, pp. F1-F34.

96-5 Koerner, R.M., Carson, D.A., Daniel, D.E., and Bonaparte, R., "Derzeitiger Stand der Testfelder mit Geosynthetischen Tondichtungsbahnen (GTDen) in Cincinnati," *Proceedings of the Symposium on Landfill Covers*, K. Czurda and K. Stief, eds., Universität Karlsruhe, Germany, 1996, pp. 3-1 to 3-29.

97-1 Sabatini, P.J., Elias, V., Schmertmann, G.R., and Bonaparte, R., "Earth Retaining Systems," *Geotechnical Circular No. 2*, Publication No. FHWA-SA-96-038, Federal Highway Administration, U.S. Department of Transportation, Washington, D.C., 1997, 161 p.

97-2 Gross, B.A., Bonaparte, R., and Othman, M.A., "Inferred Performance of Surface Hydraulic Barriers from Landfill Operational Data," *Proceedings of 1997 International Containment Technology Conference*, St. Petersburg, Feb 1997, pp. 374-380.

97-3 Carson, D.A., Daniel, D.E., Koerner, R.M., and Bonaparte, R., "Geosynthetic Clay Liners - Slope Stability Case Study," *Proceedings of the 1997 International Containment Technology Conference*, St. Petersburg, Feb 1997, pp. 381-388.

97-4 Giroud, J.P., Gross, B.A., Bonaparte, R., and McKelvey, J.A., "Leachate Flow in Leakage Collection Layers Due to Defects in Geomembrane Liners," *Geosynthetics International*, Vol. 4, Nos. 3 and 4, pp. 215-292.

97-5 Othman, M.A., Bonaparte, R., and Gross, B.A., "Preliminary Results of Composite Liner Field Performance Study," *Geotextiles and Geomembranes*, Vol. 15, Nos. 4-6, 1997, pp. 289-312.

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Geosyntec Consultants of NC, P.C.

# CCR SURFACE IMPOUNDMENT PUBLIC INFORMATION REVIEW

## COAL-FIRED ELECTRIC POWER UTILITIES GEORGIA, NORTH CAROLINA, SOUTH CAROLINA, AND VIRGINIA

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## 1. INTRODUCTION AND SCOPE

This report was prepared by Geosyntec Consultants of NC, P.C. (Geosyntec) for Duke Energy Carolinas, LLC (Duke Energy) to document our observations and findings regarding closure planning of coal combustion residual (CCR) surface impoundments in the states of Georgia, North Carolina, South Carolina, and Virginia during the approximate timeframe of 2009 to 2011, or earlier. The report presents the results of a review of two sets of publicly available documents for coal-fired electric power plants for these states:

- reports presenting the results of safety assessments for CCR impoundment dams prepared by private engineering firms under subcontract to the U.S. Environmental Protection Agency (USEPA) in the timeframe 2009-2011 (hereafter referred to as USEPA dam safety assessment reports); and,

- for the CCR impoundments identified in the USEPA dam safety assessment reports, closure plans prepared by the utility owners/operators of the CCR impoundments (or their consultants) in or around 2016 pursuant to the Federal CCR Rule (40 CFR §257.102(b)); in a few instances, the posted closure plans were prepared pursuant to state regulations rather than the CCR Rule; for this report, these facilities are considered together and collectively referred to as CCR Rule closure plans.

From the USEPA dam safety assessment reports, Geosyntec recorded information regarding each CCR impoundment's location, year built, report preparer (engineering consultant), active/inactive status, lined or unlined condition, operating information, and most relevant to this report, whether there was any indication in the report that planning for, or implementation of, an engineered impoundment closure had occurred prior to or during the 2009-2011 timeframe.

From the CCR Rule closure plans, Geosyntec recorded information about each CCR impoundment's closure plan date, closure plan preparer, closure method (e.g., closure by removal, cap-in-place), details of the closure cover system, actual or anticipated closure construction start date, and whether the CCR Rule closure plans referenced or mentioned prior closure plans (in or prior to the 2009-2011 timeframe) and/or any earlier closure planning or closure construction activities.

The results of the review of this publicly available information are contained in two tables for each of the reference states, one presenting the results of the review of the USEPA dam safety assessment reports, and the second presenting the results of the review of the CCR Rule closure plans.

## 2. QUALIFICATIONS

Geosyntec is a 37-year old, 1,400-person engineering and consulting firm with more than 50 offices across the U.S. and in several international locations. The firm practices in North Carolina through its subsidiary Geosyntec Consultants of North Carolina, P.C. (NC Engineering License C-3500). Geosyntec specializes in the areas of environmental planning and management, water and natural resources, municipal and industrial waste management facility design and permitting, and environmental remediation and restoration, amongst others.

Over the last nearly 30 years, Geosyntec has provided a wide range of engineering and consulting services to electric power utility clients. These services include siting, permitting, design, construction quality assurance (CQA), environmental monitoring, facility performance assessment, and wastewater treatment system design for CCR storage and disposal facilities. Geosyntec has provided these engineering and consulting services across the United States, including extensive involvement in projects in North Carolina and the surrounding states of Georgia, South Carolina, and Virginia.

Geosyntec also actively advances the state-of-practice through technical innovations, research collaborations with industry partners, and contributions to the technical literature. The Electric Power Research Institute (EPRI) has on several occasions contracted with Geosyntec to develop guidance manuals and research reports on CCR-related topics, including guidance on the closure of CCR surface impoundments and landfills. The firm, along with its client, Tennessee Valley Authority (TVA), received the 2014 Grand Award for Engineering Excellence from the American Council of Engineering Companies of Georgia for its work on the Peninsula Site CCR Landfill at TVA's Kingston plant in Tennessee.

The literature review for this project was conducted by Scott Sheridan, P.E. (VA) and Jintai Wang, Ph.D., EIT (VA) under the direction and review of Rudolph Bonaparte, Ph.D., P.E. (NC), NAE. The literature review was also conducted under the responsible charge of James McNash, P.E. (NC), who resides in the firm's Charlotte, North Carolina office. Dr. Bonaparte is a Senior Principal with Geosyntec. He has nearly 40 years of professional experience in the areas of geoenvironmental and geotechnical engineering applied to municipal, industrial, hazardous, and low-level radioactive waste disposal facility projects. In addition to his project experience, he was lead co-author of several technical resource and guidance documents on the design, construction, and performance of waste containment systems published by USEPA. His experience with CCR landfills and impoundments spans 25 years. He is knowledgeable regarding the physical and chemical characteristics of CCRs, the Federal CCR Rule, and the design and construction of storage, disposal, and closure systems for CCRs. Dr. Bonaparte is an elected member of the U.S. National Academy of Engineering (NA). He is a Fellow of the American Society of Civil Engineers and received the society's 2016 Lifetime Achievement Award in Design. He also received the 2019 Georgia Engineering Alliance Lifetime Achievement in Engineering Award. He is a registered professional civil engineer in 19 states.

# 3. RESULTS OF REVIEW

## 3.1 Overview

As described in Section 1, Geosyntec reviewed publicly available USEPA dam safety assessment reports and CCR Rule closure plans for CCR impoundments at electric power utility facilities for North Carolina and the bordering states of Georgia, South Carolina and Virginia. A summary of information pertinent to the purpose of this report is provided in the table below.

| State | No. of Coal-Fired Power Generating Stations Reviewed[1] | Total No. of Coal-Fired Generating Stations in State[2] | Percentage of Total Stations Reviewed for this Report (est.) | No. of CCR Impoundments Reviewed for This Report | No. of Unlined CCR Impoundments (and percentage unlined) | No. of CCR Impoundments with Indication of Historical Closure Planning[3] |
|---|---|---|---|---|---|---|
| Georgia | 11 | 13 | 85% | 30 | 28 (93%) | 1 |
| North Carolina | 14 | 16 | 88% | 30 | 27 (90%) | 0 |
| South Carolina | 9 | 11 | 82% | 22 | 19 (86%) | 0 |
| Virginia | 6 | 10 | 60% | 11 | 11 (100%) | 2 |

[1] Includes all facilities for which USEPA dam safety assessment reports were found in the on-line database.
[2] Estimate based on a review of multiple on-line information sources. Note that the scope of the review only includes coal-fired electric power utilities that stored or disposed CCRs on site (either in landfills or surface impoundments). Cogeneration facilities or privately-operated coal-fired boilers were excluded from this report.
[3] Historical in this context refers to the time frame of 2009-2011 or earlier. Note, simple placement of a layer of non-engineered fill above the CCR impoundment and/or allowing grass/vegetation to grow on the surface of the impoundment, is not recorded as "closure planning" (which is defined herein as including engineered final impoundment grades, cover system, and surface water management system), but is recorded as a "closure activity" in the more detailed discussion that follows. This closure activity is interpreted as being an extension of CCR impoundment operations.

A summary of Geosyntec's review is presented in the remainder of this section of the report. The detailed results of the review are presented in the following eight tables that can be found at the end of this report.

Table 1. Georgia – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports

Table 2. Georgia – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule

Table 3. North Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports

## 3.2 Georgia

The following observations are made based on Geosyntec's review of the USEPA dam assessment reports for Georgia (Table 1):

- only 1 of the 30 USEPA dam safety assessment reports in the Georgia review had an indication of CCR impoundment closure planning during the timeframe of the reports or during earlier periods;
- all but 2 of 30 CCR impoundments were unlined; most of the impoundments were active and receiving sluiced CCR at the time of the reports; and,
- at the time of the reports, 7 of the 30 CCR impoundments were reported as having had some closure activity. For 6 of the impoundments, the closure activity is interpreted as involving a non-engineered cover soil layer and vegetation. For one impoundment, the closure involved installation of a 2-foot thick layer of compacted clay.

The following observations are made based on Geosyntec's review of the CCR Rule closure plans for Georgia (Table 2):

- publicly available CCR Rule closure plans were found for 18 of the 30 CCR impoundments included in Geosyntec's search; of these, none had any indication in the closure plan of the existence of an earlier closure plan for the CCR impoundment (in or before the 2009-2011 timeframe) and/or any earlier closure planning or construction activities;
- the CCR Rule closure plans for the various CCR impoundments described a mix of closure methods, specifically cap-in-place, closure by removal, and closure by consolidation; and,
- the anticipated start of closure construction for these CCR impoundments ranged in the reports from 2014 to 2021.

## 3.3 North Carolina

The following observations are made based on Geosyntec's review of the USEPA dam assessment reports for North Carolina (Table 3):

- none of the 30 USEPA dam safety assessment reports in the North Carolina review had an indication of CCR impoundment closure planning during the timeframe of the reports or during earlier periods;
- all but 4 of the 30 CCR impoundments were unlined; most of the impoundments were active and receiving sluiced CCR at the time of the reports; and,
- at the time of the reports, 3 of the 30 CCR impoundments were described as being closed with a soil or vegetative cap.

The following observations are made based on Geosyntec's review of the CCR Rule closure plans for North Carolina (Table 4):

- publicly available CCR Rule closure plans were found for 21 of the 30 CCR impoundments included in Geosyntec's search; of these, none had any indication in the closure plan of the existence of an earlier closure plan for the CCR impoundment (in or before the 2009-2011 timeframe) and/or any earlier closure planning or construction activities;
- the CCR Rule closure plans for the various CCR impoundments described a mix of closure methods, specifically cap-in-place and closure by removal; and,
- the anticipated start of closure construction for these CCR impoundments ranged in the reports from 2015 to 2018.

## 3.4 South Carolina

The following observations are made based on Geosyntec's review of the USEPA dam assessment reports for South Carolina (Table 5):

- none of the 22 USEPA dam safety assessment reports in the South Carolina review had information on CCR impoundment closure planning;
- all but 3 of the 22 CCR impoundments were unlined; for two impoundments, the reports were silent on the presence or absence of a liner; most of the impoundments were active and receiving sluiced CCR at the time of the reports; and,
- at the time of the reports, none of the 22 CCR impoundments was described as having had closure activity.

The following observations are made based on Geosyntec's review of the CCR Rule closure plans for South Carolina (Table 6):

- publicly available CCR Rule closure plans were found for 19 of the 22 CCR impoundments included in Geosyntec's search; of these, none had any indication in the closure plan of the existence of an earlier closure plan for the CCR impoundment (in or before the 2009-2011 timeframe) and/or any earlier closure planning or construction activities;
- the CCR Rule closure plans for the various CCR impoundments all describe the closure method as closure by removal; and,
- the anticipated start of closure construction for the CCR impoundments ranged in the reports from 2017 to 2020; several CCR units did not have a closure construction start date but indicated closure would be complete by the end of 2020.

## 3.5 Virginia

The following observations are made based on Geosyntec's review of the USEPA dam assessment reports for Virginia (Table 7):

- only 2 of the 11 USEPA dam safety assessment reports in the Virginia review had an indication of CCR impoundment closure planning during the timeframe of the reports or during earlier periods;
- all but 1 of the 11 CCR impoundments were unlined; most of the impoundments were active and receiving sluiced CCR at the time of the reports; and,
- at the time of the reports, 2 of the 11 CCR impoundments were described as undergoing closure or preparing for closure, with closure in one case reported as covering the impoundment with compacted, dry-placed CCR and closure in the other case reported as placement of a multi-component geosynthetic cover system.

The following observations are made based on Geosyntec's review of the CCR Rule closure plans for Virginia (Table 8):

- publicly available CCR Rule closure plans were found for 9 of the 11 CCR impoundments included in Geosyntec's search; of these, one had a brief discussion of the existence of earlier closure planning (i.e., existence of a 2003 closure plan for the CCR impoundment);
- the CCR Rule closure plans for the various CCR impoundments described a mix of closure methods, specifically cap-in-place and closure by removal; and,
- the anticipated start of closure construction for these CCR impoundments ranged in the reports from 2015 to 2019.

# 4. SUMMARY

The results of Geosyntec's review of available EPA dam safety assessment reports and CCR Rule closure plans for CCR impoundments at coal-fired electric generating utilities in Georgia, North Carolina, South Carolina, and Virginia are briefly summarized as follows:

- The literature review conducted by Geosyntec included all CCR impoundments for which USEPA dam safety assessment reports are publicly available. The review includes the CCR impoundments at an estimated 40 of the 50 generating stations in the four states (80%). USEPA dam safety assessment reports were not prepared for some generating stations because CCRs at the stations were being disposed in landfills and not surface impoundments (and thus there were no dams to assess).

- Information was reviewed for 93 CCR impoundments at the 40 generating stations. Of these, only three (3.2%) CCR impoundments were identified as having engineered closure plans and/or engineering-related closure planning in the 2009-2011 timeframe, or earlier. A few additional impoundments had received a layer of non-engineered fill above the CCR impoundment and/or had grass/vegetation growing on the surface of the impoundment, but this non-engineered closure activity is interpreted herein as being a simple extension of CCR impoundment operations.

- Of the 93 CCR impoundments reviewed, 85 (91%) were either directly reported or interpreted as being unlined; most of the CCR impoundments reviewed were reported as being active in the 2009-2011 timeframe (although some were inactive), and of the active impoundments, the majority were reported as receiving sluiced CCR at the time of the USEPA dam safety assessment reports.

- Only 1 of the 57 CCR Rule closure plans had any indication of closure planning for the subject CCR impoundment for the 2009-2011 timeframe, or earlier.

# TABLES

**Table 1. Georgia – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Georgia Power Company | Kraft Power Station | Port Wentworth, GA | Ash Pond | 1958 | March 2011 | Dewberry & Davis | Active | No liner | No | No | None | None |
| Georgia Power Company | McIntosh Power Station | Rincon, GA | Ash Pond | 1982 | March 2011 | Dewberry & Davis | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Bowen | Cartersville, GA | Plant Bowen Ash Pond | 1968 | May 2009 | CHA Engineers, sub to Lockheed Martin | Active | Partially retrofitted geosynthetic clay liners(GCL), or HDPE liners, and/or clay soil liners. The lining was due to the underlying karst topography. | No | No | None | None |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond B | 1967 | November 2009 | CHA Engineers, sub to Lockheed Martin | Active | No liner | No | No | None | A portion of this pond has a soil cap of varying thickness. Trees are growing on it. There is no indication whether this was a permit requirement or not. |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond C | 1971 | November 2009 | CHA Engineers, sub to Lockheed Martin | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond D | 1980 | November 2009 | CHA Engineers, sub to Lockheed Martin | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond E | 1982 | November 2009 | CHA Engineers, sub to Lockheed Martin | Active | No liner | No | No | None | None |
| Crisp County Power Commission | Plant Crisp | Warwick, GA | CCW Impoundment, Ash Pond | 1970s | August 2012 | CDM Smith | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 1 | 1952 | April 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 2 | 1969 | April 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 3 | 1974 | April 2010 | AMEC | Inactive | No liner | No | Yes | None | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 4 | 1986 | April 2010 | AMEC | Inactive | No liner | No | No Indication | None | None |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 1 | 1964 | April 2010 | AMEC | Inactive | No liner | No | No Indication | None | The pond was removed from service at full storage capacity in 1968. The pond was filled, covered, and used as a lay-down and parking area. Interpret to be soil cover only. |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 2 | 1968 | April 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 3 | 1969 | April 2010 | AMEC | Active | No liner | No | No | None | None |

**Table 1. Georgia – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 4 | 1972 | April 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Mitchell | Albany, GA | Ash Pond 1 | 1963 | May 2010 | AMEC | Inactive | No liner | No | No Indication | None | Inactive; no longer receives liquid borne waste. The aerial photo shows that ash pond 1 was covered by vegetation. Interpret to be soil cover only. |
| Georgia Power Company | Plant Mitchell | Albany, GA | Ash Pond 2 | 1979 | May 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Mitchell | Albany, GA | Ash Pond A | 1948 | May 2010 | AMEC | Inactive | No liner | No | No Indication | None | "The pond is currently full, inactive, covered, no longer receives liquid-borne material, and is completely incised." "The site is now occupied by the combustion turbine installation." Interpret to be soil cover only. |
| Georgia Power Company | Plant Scherer | Juliette, GA | Ash Pond | 1980 | May 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Scherer | Juliette, GA | Settling Pond | 1980 | May 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Wansley | Carrolton, GA | Ash Pond | 1975 | June 2010 | Dewberry & Davis | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Ash Pond 1 | 1950 | May 2010 | AMEC | Inactive; does not currently receive CCR (does receive coal pile run off) | No liner | No | No | None | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Ash Pond 2 | 1966 | May 2010 | AMEC | Active | No liner | No | No | None | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Ash Pond 3 | 1976 | May 2010 | AMEC | Inactive; does not currently receive CCR (does receive process water discharge from Ash Pond B and storm water runoff) | No liner | No | No | None | None |
| Georgia Power Company | Plant Yates | Newnan, GA | B' Pond | 1976 | May 2010 | AMEC | Active; two active areas serve to dewater dredged ash from Ash Pond 2 | No liner | No | No | None | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Gypsum Pond | 1992 | May 2010 | AMEC | Active | HDPE Liner | No | No | None | None |

**Table 1. Georgia – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Georgia Power Company | Plant Yates | Newnan, GA | A Pond | 1975 | May 2010 | AMEC | Inactive | No liner | No | No Indication | None | Pond is covered with soil and vegetation; Inactive |
| Georgia Power Company | Plant Yates | Newnan, GA | B Pond | 1976 | May 2010 | AMEC | Inactive | No liner | No | No Indication | None | Pond is covered with soil and vegetation; Inactive |
| Georgia Power Company | Plant Yates | Newnan, GA | C Pond | 1975 - 1976 | May 2010 | AMEC | Inactive | No liner | No | No Indication | Yes | Pond is covered and inactive; Cover consists of 2 feet of clay |
| Notes | 1. Data are based on the information provided in the publicly available USEPA reports at the time of the report (~ 2009 - 2011).<br>2. Some terminologies used in the spreadsheet are directly from the original USEPA reports.<br>3. Simple placement of a layer of non-engineered fill above the CCR impoundment and/or allowing grass/vegetation to grow on the surface of the impoundment is not recorded in the table as closure planning, but is recorded as a closure activity that is interpreted to be a simple extension of CCR impoundment operations. | | | | | | | | | | | |

**Table 2. Georgia – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| Georgia Power Company | Kraft Power Station | Port Wentworth, GA | Ash Pond | Closure plan is not available. | | | | | | |
| Georgia Power Company | McIntosh Power Station | Rincon, GA | Ash Pond | October 2016 | Yes | Georgia Power | Closure by Removal | Not Applicable | 2019 (Expected) | None |
| Georgia Power Company | Plant Bowen | Cartersville, GA | Plant Bowen Ash Pond | September 2018 (Amended) | Yes | Georgia Power | Close by Consolidation | Soil-geosynthetic composite cover system or a synthetic engineered turf (ClosureTurf) | 2021 (Expected) | None |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond B | Closure plan is not available. | | | | | | |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond C | | | | | | | |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond D | | | | | | | |
| Georgia Power Company | Plant Branch | Milledgeville, GA | Ash Pond E | | | | | | | |
| Crisp County Power Commission | Plant Crisp | Warwick, GA | CCW Impoundment, Ash Pond | November 2018 | Yes | Geosyntec | Closure by Removal | Not Applicable | 2020 (Expected) | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 1 | October 2016 | Yes | Georgia Power | Closure by Removal | Not Applicable | 2019 (Expected) | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 2 | October 2016 | Yes | Georgia Power | Closure by Removal | Not Applicable | 2019 (Expected) | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 3 | April 2018 | Yes | Stantec | Close In-Place | Engineered cover system consisting of geosynthetic and soil layer | Q2 2016 | None |
| Georgia Power Company | Plant Hammond | Coosa, GA | Ash Pond 4 | Closure plan is not available. | | | | | | |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 1 | April 2019 (Amended) | Yes | Georgia Power | Close In-Place | Engineered, relatively impermeable cover system utilizing geosynthetic materials | 2016 | None |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 2 | April 2018 | Yes | Georgia Power | Closure by Removal | Not Applicable | 2016 | None |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 3 | April 2019 (Amended) | Yes | Golder | Close In-Place | Engineered cover system | Q1 2016 | None |
| Georgia Power Company | Plant McDonough | Smyrna, GA | Ash Pond 4 | April 2019 (Amended) | Yes | Golder | Close In-Place | Engineered cover system | Q1 2016 | None |
| Georgia Power Company | Plant Mitchell | Albany, GA | Ash Pond 1 | Closure plan is not available. | | | | | | |
| Georgia Power Company | Plant Mitchell | Albany, GA | Ash Pond 2 | | | | | | | |
| Georgia Power Company | Plant Mitchell | Albany, GA | Ash Pond A | | | | | | | |
| Georgia Power Company | Plant Scherer | Juliette, GA | Ash Pond | October 2016 | Yes | Georgia Power | Close In-Place | Final cover design not yet complete | 2019 (Expected) | None |
| Georgia Power Company | Plant Scherer | Juliette, GA | Settling Pond | Closure plan is not available. | | | | | | |
| Georgia Power Company | Plant Wansley | Carrolton, GA | Ash Pond | October 2016 | Yes | Georgia Power | Close In-Place | Final cover design not yet complete | 2019 (Expected) | None |

**Table 2. Georgia – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| Georgia Power Company | Plant Yates | Newnan, GA | Ash Pond 1 | April 2018 | Yes | Georgia Power | Closure by Removal | Not Applicable | July 2015 | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Ash Pond 2 | October 2016 | Yes | Georgia Power | Closure by Removal | Not Applicable | 2019 (Expected) | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Ash Pond 3 | October 2016 | Yes | Georgia Power | Close In-Place | Final cover design not yet complete | 2019 (Expected) | None |
| Georgia Power Company | Plant Yates | Newnan, GA | B' Pond | October 2016 | Yes | Georgia Power | Close In-Place | Final cover design not yet complete | 2019 (Expected) | None |
| Georgia Power Company | Plant Yates | Newnan, GA | Gypsum Pond | Closure plan is not available. | | | | | | |
| Georgia Power Company | Plant Yates | Newnan, GA | A Pond | April 2018 | Yes | Georgia Power | Closure by Removal | Not Applicable | October 2014 | None |
| Georgia Power Company | Plant Yates | Newnan, GA | B Pond | September 2018 (Amended) | Yes | Georgia Power | Closure by Removal | Not Applicable | 2019 (Expected) | None |
| Georgia Power Company | Plant Yates | Newnan, GA | C Pond | Closure plan is not available. | | | | | | |
| Notes | 1. Data are based on the information provided in the publicly available Closure Plans.<br>2. Some terminologies used in the spreadsheet are directly from the original Closure Plans. | | | | | | | | | |

**Table 3. North Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy | Belews Creek | Walnut Cove, NC | Active Ash Pond | 1970-1972 | September 2009 | CHA Engineers, sub to Lockheed Martin | Active; Receiving sluiced CCR | No Liner | No | No | None | None |
| Duke Energy | Buck Steam Station | Spencer, NC | New Primary Pond | 1956 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy | Buck Steam Station | Spencer, NC | Primary Pond | 1977 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy | Buck Steam Station | Spencer, NC | Secondary Pond | 1977 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy | Dan River | Eden, NC | Primary Pond | 1967-1977 | May 2009 | RIZZO, sub to Lockheed Martin | Active | No Liner | The Primary Pond has been dredged at various times in its life, with the dredge spoils stored on site in a dry ash storage landfill. | No | None | None |
| Duke Energy | Dan River | Eden, NC | Secondary Pond | 1967-1977 | May 2009 | RIZZO, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy | Allen Steam Station | Belmont, NC | Active Ash Pond | 1965 | June 2009 | GZA GeoEnvironmental, sub to Lockheed Martin | Active. Take relatively small amount of slurry, as ash from dry process is going to an onsite landfill. | No Liner | No | No | None | None |
| Duke Energy | Marshall Steam Station | Catawba County, NC | Active Ash Pond | 1965 | May 2009 | GZA GeoEnvironmental, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy | Riverbend Steam Station | Mt. Holly, NC | Primary Pond | 1957 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy | Riverbend Steam Station | Mt. Holly, NC | Secondary Pond | 1979 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Duke Energy Corp | Cliffside Power Station | Mooresboro, NC | Active Pond | Late 80s | February 2011 | Dewberry & Davis | Active | No Liner | No | No | None | None |
| Duke Energy Corp | Cliffside Power Station | Mooresboro, NC | Retired Unit 1-4 Basin | N/A | February 2011 | Dewberry & Davis | Inactive. Unit has been repurposed to manage stormwater runoff from the site. | No Liner | Yes. There may be minimal amounts of ash remaining. | Yes | None | None |
| Duke Energy Corp | Cliffside Power Station | Mooresboro, NC | Retired Unit 5 Basin | N/A | February 2011 | Dewberry & Davis | Inactive; No longer receive ash or impound water | No Liner | No | Yes | None | Closed; Capped with soil |
| Progress Energy | Roxboro | Person County, NC | West Ash Pond | 1973 | September 2009 | RIZZO, sub to Lockheed Martin | Active | No Liner | No | No | None | None |

**Table 3. North Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Progress Energy | Roxboro | Person County, NC | FGD Flush Pond | 2007 | September 2009 | RIZZO, sub to Lockheed Martin | Active | Geomembrane Liner | Not Applicable | No Indication | None | None |
| Progress Energy | Roxboro | Person County, NC | FGD Settling Pond | 2007 | September 2009 | RIZZO, sub to Lockheed Martin | Active | Geosynthetic Clay Liner | Not Applicable | No Indication | None | None |
| Progress Energy | Asheville Electric Plant | Buncombe County, NC | 1964 Pond | 1964 | May 2009 | Dewberry & Davis | Inactive; Pond was removed from service in 1982. | Geomembrane Liner | No | Pond was drained in 1982. | None | None |
| Progress Energy | Asheville Electric Plant | Buncombe County, NC | 1982 Pond | 1982 | May 2009 | Dewberry & Davis | Active | No Liner | No | No | None | None |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1956 Ash Pond | 1956 | June 2009 | CHA Engineers, sub to Lockheed Martin | Inactive. "At present, the pond no longer impounds water and is overgrown with trees and heavy vegetation". | No Liner | No | No Indication | None | Closed; Vegetation Cap |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1963/1970 Ash Pond | 1963/1970 | June 2009 | CHA Engineers, sub to Lockheed Martin | Inactive. "No longer receives CCW or storm water discharges from the plant". | No Liner | No | No Indication | None | Closed; Vegetation Cap |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1978 Ash Pond | 1978 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active; Receiving storm water, coal pile run off and low-volume categorical waste water from plant; Does not receive CCR | No Liner | No | No | None | None |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1985 Ash Pond | 1985 | June 2009 | CHA Engineers, sub to Lockheed Martin | Active; Receiving sluiced CCR | No Liner | No | No | None | None |
| Progress Energy | Mayo Generating Plant | Roxboro, NC | 1982 Pond | 1982 | June 2009 | Dewberry & Davis, sub to Lockheed Martin | Active | No Liner | No | No | None | None |
| Progress Energy Carolinas Inc | L. V. Sutton Power Station | Wilmington, NC | 1971 Pond | 1971 | February 2011 | Dewberry & Davis | Active | No Liner | No | No | None | None |
| Progress Energy Carolinas Inc | L. V. Sutton Power Station | Wilmington, NC | 1984 Pond | 1984 | February 2011 | Dewberry & Davis | Active | One-foot thick clay liner on the interior face. The clay lining was covered with a two-foot thick protective sand fill. | No | No | None | None |
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Active Ash Pond | 1980 | February 2011 | Dewberry & Davis | Active | No Liner | No | No | None | None |

**Table 3. North Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Inactive Ash Pond 1 | 1950s and 1960s | February 2011 | Dewberry & Davis | Inactive; Taken out of service in 1973 and have not been used since | No Liner | No | No Indication | None | None |
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Inactive Ash Pond 2 | 1950s and 1960s | February 2011 | Dewberry & Davis | Inactive; Taken out of service in 1973 and have not been used since | No Liner | No | No Indication | None | None |
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Inactive Ash Pond 3 | 1950s and 1960s | February 2011 | Dewberry & Davis | Inactive; Taken out of service in 1973 and have not been used since | No Liner | No | No Indication | None | None |
| Progress Energy Carolinas Inc | W. H. Weatherspoon Power Station | Lumberton, NC | 1979 Pond | 1979 | February 2011 | Dewberry & Davis | Active | No Liner | No | No Indication | None | None |
| Notes | 1. Data are based on the information provided in the publicly available USEPA reports at the time of the report (~ 2009 - 2011).<br>2. Some terminologies used in the spreadsheet are directly from the original USEPA reports.<br>3. Simple placement of a layer of non-engineered fill above the CCR impoundment and/or allowing grass/vegetation to grow on the surface of the impoundment is not recorded in the table as closure planning, but is recorded as a closure activity that is interpreted to be a simple extension of CCR impoundment operations. | | | | | | | | | | | |

**Table 4. North Carolina – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy | Belews Creek | Walnut Cove, NC | Active Ash Pond | October 2016 | Yes | AECOM | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Duke Energy | Buck Steam Station | Spencer, NC | New Primary Pond | October 2016 | Yes | HDR | Closure by Removal | Not Applicable | 2018 (Expected) | None |
| Duke Energy | Buck Steam Station | Spencer, NC | Primary Pond | October 2016 | Yes | HDR | Closure by Removal | Not Applicable | 2018 (Expected) | None |
| Duke Energy | Buck Steam Station | Spencer, NC | Secondary Pond | October 2016 | Yes | HDR | Closure by Removal | Not Applicable | 2018 (Expected) | None |
| Duke Energy | Dan River | Eden, NC | Primary Pond | October 2016 | Yes | Amec Foster Wheeler | Closure by Removal | Not Applicable | 2017 (Expected) | None |
| Duke Energy | Dan River | Eden, NC | Secondary Pond | October 2016 | Yes | Amec Foster Wheeler | Closure by Removal | Not Applicable | 2017 (Expected) | None |
| Duke Energy | Allen Steam Station | Belmont, NC | Active Ash Pond | October 2016 | Yes | AECOM | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Duke Energy | Marshall Steam Station | Catawba County, NC | Active Ash Pond | October 2016 | Yes | AECOM | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Duke Energy | Riverbend Steam Station | Mt. Holly, NC | Primary Pond | According to Duke Energy Website, the CCR rule does not apply to this site. No closure plan is available. | | | | | | |
| Duke Energy | Riverbend Steam Station | Mt. Holly, NC | Secondary Pond | According to Duke Energy Website, the CCR rule does not apply to this site. No closure plan is available. | | | | | | |
| Duke Energy Corp | Cliffside Power Station | Mooresboro, NC | Active Pond | October 2016 | Yes | Amec Foster Wheeler | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Duke Energy Corp | Cliffside Power Station | Mooresboro, NC | Retired Unit 1-4 Basin | October 2016 | Yes | Amec Foster Wheeler | Closure by Removal | Not Applicable | 2017 (Expected) | None |
| Duke Energy Corp | Cliffside Power Station | Mooresboro, NC | Retired Unit 5 Basin | October 2016 | Yes | Amec Foster Wheeler | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Progress Energy | Roxboro | Person County, NC | West Ash Pond | October 2016 | Yes | Amec Foster Wheeler | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Progress Energy | Roxboro | Person County, NC | FGD Flush Pond | October 2016 | Yes | Amec Foster Wheeler | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Progress Energy | Roxboro | Person County, NC | FGD Settling Pond | October 2016 | Yes | Amec Foster Wheeler | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Progress Energy | Asheville Electric Plant | Buncombe County, NC | 1964 Pond | October 2016 | Yes | Amec Foster Wheeler | Closure by Removal | Not Applicable | 2018 (Expected) | None |
| Progress Energy | Asheville Electric Plant | Buncombe County, NC | 1982 Pond | October 2016 | Yes | Amec Foster Wheeler | Closure by Removal | Not Applicable | 2015 | None |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1956 Ash Pond | According to Duke Energy Website, the CCR rule does not apply to this site. No closure plan is available. | | | | | | |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1963/1970 Ash Pond | | | | | | | |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1978 Ash Pond | | | | | | | |
| Progress Energy | Cape Fear Plant | Moncure, NC | 1985 Ash Pond | | | | | | | |
| Progress Energy | Mayo Generating Plant | Roxboro, NC | 1982 Pond | October 2016 | Yes | AECOM | Cap-in-Place | Engineered cover system consisting of geosynthetics and soil | 2018 (Expected) | None |
| Progress Energy Carolinas Inc | L. V. Sutton Power Station | Wilmington, NC | 1971 Pond | October 2016 | Yes | Geosyntec | Closure by Removal | Not Applicable | 2015 | None |
| Progress Energy Carolinas Inc | L. V. Sutton Power Station | Wilmington, NC | 1984 Pond | October 2016 | Yes | Geosyntec | Closure by Removal | Not Applicable | 2015 | None |

**Table 4. North Carolina – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Active Ash Pond | October 2016 | Yes | Geosyntec | Closure by Removal | Not Applicable | 2018 (Expected) | None |
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Inactive Ash Pond 1 | Closure plan not available | | | | | | |
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Inactive Ash Pond 2 | | | | | | | |
| Progress Energy Carolinas Inc | H.F. Lee Power Station | Goldsboro, NC | Inactive Ash Pond 3 | | | | | | | |
| Progress Energy Carolinas Inc | W. H. Weatherspoon Power Station | Lumberton, NC | 1979 Pond | October 2016 | Yes | S&ME | Closure by Removal | Not Applicable | 2018 (Expected) | None |
| Notes | 1. Data are based on the information provided in the publicly available Closure Plans.<br>2. Some terminologies used in the spreadsheet are directly from the original Closure Plans. | | | | | | | | | |

**Table 5. South Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy | WS Lee Power Station | Pelzer, SC | Primary Active Ash Pond | 1974 | June 2010 | GEI Consultants | Receives wet sluiced fly ash, bottom ash and other plant waste. | No Liner | Yes. Sometime after 1995 the operator began dredging ash and placing it in a dry disposal landfill. | Ash removal was via dredging. There is no indication that dewatering occurred within the pond. | None | None |
| Duke Energy | WS Lee Power Station | Pelzer, SC | Secondary Ash Pond | 1975 | June 2010 | GEI Consultants | Receives discharge from Primary Ash Pond. | No Liner | No indication | No | None | None |
| Santee Cooper | Grainger Generating Station | Conway, SC | Ash Pond 1 | 1966 | June 2010 | GEI Consultants | Operates as dry CCR storage for CCR taken from Ash Pond 2. | No indication | No. Ash pond is used to store dry ash. | Yes, as part of dry stack operation. Water is discharged to Ash Pond 2 | None | None |
| Santee Cooper | Grainger Generating Station | Conway, SC | Ash Pond 2 | 1977 | June 2010 | GEI Consultants | Received fly ash, bottom ash, and boiler slag. CCR is dewatered and disposed in Ash Pond 1. | No indication | Yes, for disposal in Ash Pond 1. | No | None | None |
| Santee Cooper | Jeffries Generating Station | Moncks Corner, SC | Ash Pond A | ~1970 | June 2010 | Dewberry & Davis | Receives fly ash and bottom ash. CCR is dewatered and excavated for beneficial use. Sluice water discharges to Ash Pond B. | No Liner | Yes, for beneficial use. | No | None | None |
| Santee Cooper | Jeffries Generating Station | Moncks Corner, SC | Ash Pond B | ~1970 | June 2010 | Dewberry & Davis | Receives discharge from Ash Pond A. | No Liner | No | No | None | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Ash Pond A | 1975 | June 2010 | Dewberry & Davis | Receives fly ash sluice water when beneficial use operation is down. | No Liner | Yes, for beneficial use. | No | None | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Ash Pond B | 1975 | June 2010 | Dewberry & Davis | Receives discharge water from Ash Pond A. | No Liner | No | No | None | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Slurry Pond 2 | 1977 | June 2010 | Dewberry & Davis | Inactive | No Liner | No | No | None | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | South Ash Pond | 1980 | June 2010 | Dewberry & Davis | Receives fly ash sluice water when beneficial use operation is down. | No Liner | No | No | None | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Units 3&4 Slurry Pond | 1980 | June 2010 | Dewberry & Davis | Occasionally receives FGD slurry from plant. | No Liner | No | No | None | None |

Table 5. South Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Santee Cooper | Winyah Generating Station | Georgetown, SC | West Ash Pond | 1980 | June 2010 | Dewberry & Davis | Inactive | No Liner | No | No | None | None |
| Santee Cooper | Cross Generating Station | Pineville, SC | Bottom Ash 1 | 1983 | February 2011 | Dewberry & Davis | Receives sluiced bottom ash, economizer ash, and secondary boiler slag. | 6-inch soil bentonite layer | CCR is occasionally excavated for beneficial use. | CCR excavated for beneficial use is dewatered prior to transport. | None | None |
| Santee Cooper | Cross Generating Station | Pineville, SC | Bottom Ash 2 | 1995 | February 2011 | Dewberry & Davis | Receives sluiced bottom ash, economizer ash, and secondary boiler slag. | Geosynthetic clay | CCR is occasionally excavated for beneficial use. | CCR excavated for beneficial use is dewatered prior to transport. | None | None |
| Santee Cooper | Cross Generating Station | Pineville, SC | Gypsum Pond | 1983 | February 2011 | Dewberry & Davis | Active | 6-inch soil bentonite layer | No | No | None | None |
| SCE&G | Canadys Steam Power Station | Canadys, SC | Active Ash Pond | 1987 | February 2011 | Dewberry & Davis | Receives plant process waste water, coal combustion waste, coal pile stormwater runoff, and other stormwater runoff | No Liner | No | No | None | None |
| SCE&G | Canadys Steam Power Station | Canadys, SC | Inactive Ash Pond | 1974 | February 2011 | Dewberry & Davis | Inactive | No Liner | No | No | None | None |
| SCE&G | Wateree Station | Eastover, SC | Ash Pond 1 | 1970 | June 2010 | Dewberry & Davis | Receives cooling tower blowdown, low volume wastes, ash transport wastewaters, landfill runoff/leachate, coal pile runoff, miscellaneous power plant wastewaters and storm water | No Liner | No | No | None | None |
| SCE&G | Wateree Station | Eastover, SC | Ash Pond 2 | 1970 | June 2010 | Dewberry & Davis | Receives effluent from Ash Pond 1 | No Liner | No | No | None | None |
| SCE&G | Urquhart Generating Station | Beech Island, SC | Ash Pond 1 | 1953 | February 2011 | Dewberry & Davis | Receives minimal amounts of CCR from sluice water overflow and minimal amounts of stormwater | No Liner | Ponds are periodically dredged for ash removal | No | None | None |
| SCE&G | Urquhart Generating Station | Beech Island, SC | Ash Pond 2 | 1953 | February 2011 | Dewberry & Davis | Receives minimal amounts of CCR from sluice water overflow and minimal amounts of stormwater | No Liner | Ponds are periodically dredged for ash removal | No | None | None |

**Table 5. South Carolina – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Progress Energy | HB Robinson Steam Electric Plant | Hartsville, SC | Ash Pond | 1960 | February 2011 | Dewberry & Davis | Receiving sluiced bottom ash, boiler slag, ash sluice water, stormwater and metal cleaning chemicals | No liner | No | No | None | None |
| Notes | 1. Data are based on the information provided in the publicly available USEPA reports at the time of the report (~ 2009 - 2011).<br>2. Some terminologies used in the spreadsheet are directly from the original USEPA reports.<br>3. Simple placement of a layer of non-engineered fill above the CCR impoundment and/or allowing grass/vegetation to grow on the surface of the impoundment is not recorded in the table as closure planning, but is recorded as a closure activity that is interpreted to be a simple extension of CCR impoundment operations. | | | | | | | | | | | |

**Table 6. South Carolina – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy | WS Lee Power Station | Pelzer, SC | Primary Active Ash Pond | October 2016 | Yes | AECOM | Closure by Removal | Not Applicable | End of 2018 (Expected) | None |
| Duke Energy | WS Lee Power Station | Pelzer, SC | Secondary Ash Pond | October 2016 | Yes | AECOM | Closure by Removal | Not Applicable | End of 2018 (Expected) | None |
| Santee Cooper | Grainger Generating Station | Conway, SC | Ash Pond 1 | January 2014 | Yes | Geosyntec Consultants | Closure by Removal | Not Applicable | No start date indicated. Excavation of ash and soil was planned to be complete by December 31, 2020. | None |
| Santee Cooper | Grainger Generating Station | Conway, SC | Ash Pond 2 | January 2014 | Yes | Geosyntec Consultants | Closure by Removal | Not Applicable | No start date indicated. Excavation of ash and soil was planned to be complete by December 31, 2020. | None |
| Santee Cooper | Jeffries Generating Station | Moncks Corner, SC | Ash Pond A | May 2016 | Prepared in response to SCDHEC regulations | Geosyntec Consultants | Closure by Removal | Not Applicable | Excavation for beneficiation; Ongoing since 2014; Closure to continue as part of excavation. | None |
| Santee Cooper | Jeffries Generating Station | Moncks Corner, SC | Ash Pond B | May 2016 | Prepared in response to SCDHEC regulations | Geosyntec Consultants | Closure by Removal | Not Applicable | Excavation for beneficiation; Ongoing since 2014; Closure to continue as part of excavation. | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Ash Pond A | October 2019 | Yes | Santee Cooper | Closure by Removal | Not Applicable | October 2020 | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Ash Pond B | October 2019 | Yes | Santee Cooper | Closure by Removal | Not Applicable | October 2020 | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Slurry Pond 2 | September 2015 | Prepared in response to SCDHEC regulations | Geosyntec Consultants | Closure by Removal | Not Applicable | Completed November 2017 | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | South Ash Pond | October 2016 | Yes | Geosyntec Consultants | Closure by Removal | Not Applicable | May 2018 | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | Units 3&4 Slurry Pond | October 2016 | Yes | Geosyntec Consultants | Closure by Removal | Not Applicable | May 2018 | None |
| Santee Cooper | Winyah Generating Station | Georgetown, SC | West Ash Pond | September 2015 | Prepared in response to SCDHEC regulations | Geosyntec Consultants | Closure by Removal | Not Applicable | Completed November 2017 | None |
| Santee Cooper | Cross Generating Station | Pineville, SC | Bottom Ash 1 | August 2019 | Yes | Santee Cooper | Closure by Removal | Not Applicable | October 2020 | None |
| Santee Cooper | Cross Generating Station | Pineville, SC | Bottom Ash 2 | August 2019 | Yes | Santee Cooper | Closure by Removal | Not Applicable | October 2020 | None |
| Santee Cooper | Cross Generating Station | Pineville, SC | Gypsum Pond | January 2016 | Prepared in response to SCDHEC regulations | Worley Parsons | Closure by Removal | Not Applicable | Completed March 2017 | None |
| SCE&G | Canadys Steam Power Station | Canadys, SC | Active Ash Pond | March 2016 | Prepared in response to SCDHEC regulations | Garrett & Moore | Closure by Removal | Not Applicable | February 2017 | None |
| SCE&G | Canadys Steam Power Station | Canadys, SC | Inactive Ash Pond | Closure plan is not available. According to EPA report, the pond was inactive. Ash was removed and a slurry wall constructed around the pond by 1996. | | | | | | |
| SCE&G | Wateree Station | Eastover, SC | Ash Pond 1 | October 2016 | Yes | Garrett & Moore | Closure by Removal | None | 2/1/2017, closure complete December 2019 | None |
| SCE&G | Wateree Station | Eastover, SC | Ash Pond 2 | October 2016 | Yes | Garrett & Moore | Closure by Removal | None | 2/1/2017, closure complete December 2019 | None |

**Table 6. South Carolina – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| SCE&G | Wateree Station | Eastover, SC | FGD Pond | September 2016 | Yes | Garrett & Moore | Closure by Removal | None | None indicated; however, closure may assumed to be ongoing or complete. | This pond was not included in EPA Report for Station. |
| SCE&G | Urquhart Generating Station | Beech Island, SC | Ash Pond 1 | Closure plan is not available. No further information was found regarding the closure plan for this pond. | | | | | | |
| SCE&G | Urquhart Generating Station | Beech Island, SC | Ash Pond 2 | Closure plan is not available. No further information was found regarding the closure plan for this pond. | | | | | | |
| Progress Energy | HB Robinson Steam Electric Plant | Hartsville, SC | Ash Pond | October 2016 | Yes | HDR Engineering | Closure by Removal | None | End of 2018 (Expected) | None |
| Notes | 1. Data are based on the information provided in the publicly available Closure Plans.<br>2. Some terminologies used in the spreadsheet are directly from the original Closure Plans. | | | | | | | | | |

**Table 7. Virginia – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dominion | Possum Point Power Station | Dumfries, VA | Ash Pond D | 1988 | April 2010 | O'Brien & Gere | Not receiving ash; Receiving stormwater and river dredged material | Reportedly designed with a 2-foot thick clay liner on the bottom of the pond. | No | No | None | None |
| Dominion | Possum Point Power Station | Dumfries, VA | Ash Pond E | 1968 | April 2010 | O'Brien & Gere | Not receiving ash; Receiving stormwater and disposed water from generating site processes | No Liner | No | No | None | None |
| Dominion | Chesapeake Energy Center | Chesapeake, VA | Bottom Ash and Sedimentation Pond | 1984 | May 2010 | O'Brien & Gere | Receiving sluiced ash, stormwater runoff and leachate from landfill, etc. | No Liner | Yes. The slurry was continuously dewatered and CCR was then moved to a dry-disposal landfill. | Yes. The slurry was continuously dewatered and CCR was then moved to a dry-disposal landfill. | None | None |
| Dominion | Chesterfield Power Station | Chester, VA | Lower Ash Pond | 1964 | April 2010 | O'Brien & Gere | Receiving sluiced CCR | No Liner | Yes. CCR was stockpiled to drain and then hauled to the Upper Ash Pond. | No. CCR was only stockpiled to drain. | None | None |
| Dominion | Chesterfield Power Station | Chester, VA | Upper Ash Pond | 1983 | April 2010 | O'Brien & Gere | Receiving dried and compacted CCR | No Liner | No | No | Yes | "Upon reaching its volume capacity, wet disposal of CCW in the Upper Ash Pond was discontinued and the impoundment is currently undergoing closure procedures. The closure design includes dry disposal of additional ash above the filled-in surface of the wet disposal impoundment. Closure of the Upper Ash Pond began in 2002 and continues as of the date of this report. Closure will include capping the filled Upper Ash Pond with compacted dry-placed ash excavated from the Lower Ash Pond. Upon commencement of closure operations in 2002, liquid-borne placement of CCW was terminated." |
| Dominion | Bremo Bluff Power Station | Bremo Bluff, VA | North Ash Pond | 1983 | April 2010 | O'Brien & Gere | Receiving dredged CCR from West Ash Pond | No Liner | No | No | None | None |
| Dominion | Bremo Bluff Power Station | Bremo Bluff, VA | West ash pond | 1978-1979 | April 2010 | O'Brien & Gere | Receiving sluiced CCR | No Liner | CCR was dredged and hydraulically transferred to North Ash Pond. | No | None | None |
| American Electric Power | Appalachian Power Co - Glen Lyn Power Station | Glen Lyn, VA | Fly Ash Pond | 1965 | February 2011 | Dewberry & Davis | Inactive; Pond is empty of CCR | No Liner | No | No | None | None |
| American Electric Power | Appalachian Power Co - Glen Lyn Power Station | Glen Lyn, VA | Bottom Ash Pond | 1963 | February 2011 | Dewberry & Davis | Receiving sluiced bottom ash | No Liner | Yes. Bottom ash was hauled offsite for permitted disposal. | Yes | None | None |
| American Electric Power | Appalachian Power Co - Clinch River | Carbo, VA | Bottom Ash Pond 1A/1B | 1955 | February 2011 | Dewberry & Davis | Receiving sluiced CCR | No Liner | No | No | None | None |

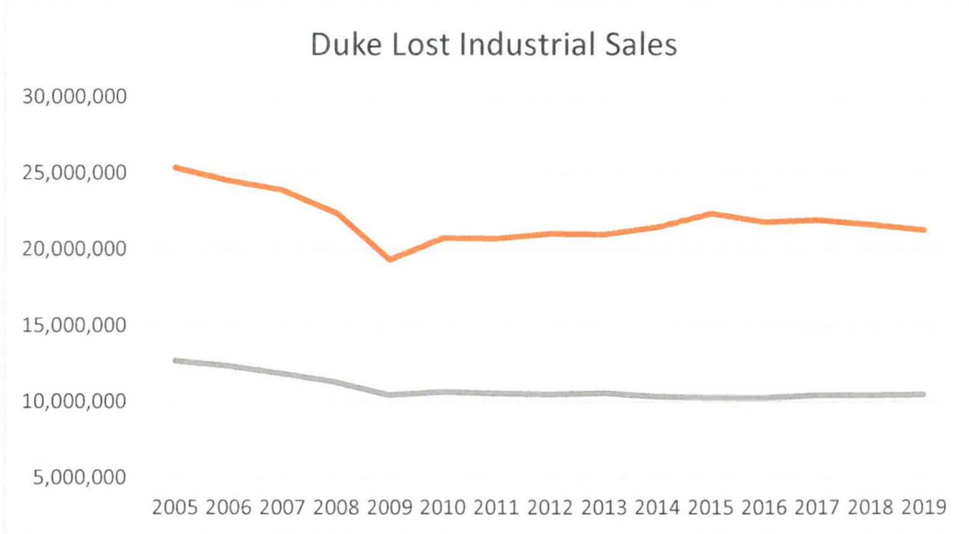
**Table 7. Virginia – Review of Publicly Available USEPA CCR Impoundment Dam Safety Assessment Reports**

| Company | Facility | Location | Coal Ash Pond | Year Built | Date of Inspection | Report Preparer | Operational Status at Time of Inspection | Lined or Unlined Condition | Ash Removed from Basin (Yes/No) | Ash Basin Dewatering (Yes/No) | Indication of Closure Planning in USEPA Report | Available Description of Closure Activities in USEPA Report for 2009 - 2011 Time Frame (or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| American Electric Power | Appalachian Power Co - Clinch River | Carbo, VA | Bottom Ash Pond 2 | 1954 | February 2011 | Dewberry & Davis | Inactive; Not receiving CCR | No Liner | No | Dewatered in 1998 and has been out of service since then. | Yes | A closure plan dated January 15, 2009 was appended to the USEPA report. Closure plan states: "The re-graded ash surface will be covered with a flexible geomembrane covered by a geocomposite drainage layer and 2-feet of soil fill." |
| Notes | 1. Data are based on the information provided in the publicly available USEPA reports at the time of the report (~ 2009 - 2011).<br>2. Some terminologies used in the spreadsheet are directly from the original USEPA reports.<br>3. Simple placement of a layer of non-engineered fill above the CCR impoundment and/or allowing grass/vegetation to grow on the surface of the impoundment is not recorded in the table as closure planning, but is recorded as a closure activity that is interpreted to be a simple extension of CCR impoundment operations. | | | | | | | | | | | |

**Table 8. Virginia – Review of Publicly Available Utility CCR Impoundment Closure Plans Prepared Pursuant to Federal CCR Rule**

| Company | Facility | Location | Coal Ash Pond | Closure Plan Date | Prepared in Response to CCR Rule | Closure Plan Preparer | Closure Plan Proposed for CCR Rule Compliance | Closure Cover System Proposed for CCR Rule Compliance | Closure Construction Start Date | Indication of Historical Closure Planning (2011 or earlier) |
|---|---|---|---|---|---|---|---|---|---|---|
| Dominion | Possum Point Power Station | Dumfries, VA | Ash Pond D | October 2016 | Yes | GAI | Cap-in-Place | Engineered cover system consisting of geomembrane and soil layers | February 2017 (Expected) | None |
| Dominion | Possum Point Power Station | Dumfries, VA | Ash Pond E | October 2016 | Yes | GAI | Closure by Removal | Not Applicable | June 2015 | None |
| Dominion | Chesapeake Energy Center | Chesapeake, VA | Bottom Ash and Sedimentation Pond | April 2018 | Yes | Golder | Closure by Removal | Engineered liner system consisting of geomembrane and cover soil layers | January 2019 (Expected) | None |
| Dominion | Chesterfield Power Station | Chester, VA | Lower Ash Pond | October 2016 | Yes | Geosyntec | Cap-in-Place | Engineered cover system consisting of geomembrane and soil layers | May 2017 (Expected) | None |
| Dominion | Chesterfield Power Station | Chester, VA | Upper Ash Pond | October 2016 | Yes | GAI | Cap-in-Place | Engineered cover system consisting of geomembrane and soil layers | April 2017 (Expected) | A 2003 Closure Plan (Modified in 2015) was mentioned in the text. The 2003 Closure Plan was incorporated into the Station's VPDES permit. The 2003 Closure Plan was not found. |
| Dominion | Bremo Bluff Power Station | Bremo Bluff, VA | North Ash Pond | October 2016 | Yes | Golder | Cap-in-Place | Engineered cover system consisting of geomembrane and soil layers | May 2017 (Expected) | None |
| Dominion | Bremo Bluff Power Station | Bremo Bluff, VA | West ash pond | May 2018 | Yes | Golder | Closure by Removal | Not Applicable | Already started. "At the time of writing, the majority of CCR in the ponds has been relocated to the North Ash Pond". | None |
| American Electric Power | Appalachian Power Co - Glen Lyn Power Station | Glen Lyn, VA | Fly Ash Pond | Closure plan is not available. According to EPA report, the pond was inactive and empty of coal ash. | | | | | | |
| American Electric Power | Appalachian Power Co - Glen Lyn Power Station | Glen Lyn, VA | Bottom Ash Pond | Closure plan is not available. According to EPA report, the bottom ash was hauled offsite for permitted disposal. | | | | | | |
| American Electric Power | Appalachian Power Co - Clinch River | Carbo, VA | Bottom Ash Pond 1A/1B | July 2017 | Yes | Amec Foster Wheeler | Cap-in-Place | "Impermeable cap with vegetative cover" | June 2017 (Expected) | None |
| American Electric Power | Appalachian Power Co - Clinch River | Carbo, VA | Bottom Ash Pond 2 | January 2009 | No | BBCM | Cap-in-Place | "A flexible geomembrane covered by a geocomposite drainage layer and 2-feet of soil fill" | No Indication | None |
| Notes | 1. Data are based on the information provided in the publicly available Closure Plans.<br>2. Some terminologies used in the spreadsheet are directly from the original Closure Plans. | | | | | | | | | |

I/A




| Year | DEC Ind. Sales (MWH) | DEP Ind. Sales (MWH) |
|---|---|---|
| 2005 | 25,376,288 | 12,693,422 |
| 2006 | 24,510,481 | 12,364,156 |
| 2007 | 23,893,374 | 11,860,042 |
| 2008 | 22,412,527 | 11,314,662 |
| 2009 | 19,359,267 | 10,475,350 |
| 2010 | 20,739,589 | 10,655,104 |
| 2011 | 20,699,985 | 10,563,125 |
| 2012 | 21,026,608 | 10,497,518 |
| 2013 | 20,983,858 | 10,582,152 |
| 2014 | 21,482,195 | 10,340,709 |
| 2015 | 22,352,679 | 10,274,406 |
| 2016 | 21,782,414 | 10,266,479 |
| 2017 | 21,922,218 | 10,417,125 |
| 2018 | 21,623,383 | 10,420,725 |
| 2019 | 21,271,896 | 10,473,676 |

Source: snl.com

| Year | DEC | DEP |
|---|---|---|
| 2005 | 25,376,288 | 12,693,422 |
| 2019 | 21,271,896 | 10,473,676 |
| **Diff (MWHs)** | **4,104,392** | **2,219,746** |
| **Diff (%)** | **16.2%** | **17.5%** |

Recently Authorized ROEs by RRA Ranking

| | | | | | | | | | Authorized ROE | | | Authorized Equity Ratio | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | Equity Ratio (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
| Washington | Avista Corp. | D-UE-150204 | Electric | Vertically Integrated | 1/6/2016 | 9.50 | 48.50 | Average / 3 | | | 9.50 | | | 48.50 |
| Arkansas | Entergy Arkansas LLC | D-15-015-U | Electric | Vertically Integrated | 2/23/2016 | 9.75 | NA | Average / 3 | | | 9.75 | | | NA |
| Indiana | Indianapolis Power & Light Co. | Ca-44576 | Electric | Vertically Integrated | 3/16/2016 | 9.85 | NA | Above Average / 3 | 9.85 | | | NA | | |
| New Mexico | El Paso Electric Co. | C-15-00127-UT | Electric | Vertically Integrated | 6/8/2016 | 9.48 | 49.29 | Below Average / 1 | | | 9.48 | | | 49.29 |
| Indiana | Northern IN Public Svc Co. | Ca-44688 | Electric | Vertically Integrated | 7/18/2016 | 9.98 | NA | Above Average / 3 | 9.98 | | | NA | | |
| Tennessee | Kingsport Power Company | D-16-00001 | Electric | Vertically Integrated | 8/9/2016 | 9.85 | 40.25 | Average / 1 | 9.85 | | | 40.25 | | |
| Arizona | UNS Electric Inc. | D-E-04204A-15-0142 | Electric | Vertically Integrated | 8/18/2016 | 9.50 | 52.83 | Average / 3 | | | 9.50 | | | 52.83 |
| Washington | PacifiCorp | D-UE-152253 | Electric | Vertically Integrated | 9/1/2016 | 9.50 | 49.10 | Average / 3 | | | 9.50 | | | 49.10 |
| Michigan | Upper Peninsula Power Co. | C-U-17895 | Electric | Vertically Integrated | 9/8/2016 | 10.00 | NA | Average / 1 | 10.00 | | | NA | | |
| New Mexico | Public Service Co. of NM | C-15-00261-UT | Electric | Vertically Integrated | 9/28/2016 | 9.58 | 49.61 | Below Average / 1 | | | 9.58 | | | 49.61 |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-121 (Elec) | Electric | Vertically Integrated | 11/9/2016 | 9.80 | 57.16 | Above Average / 2 | 9.80 | | | 57.16 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201500208 | Electric | Vertically Integrated | 11/10/2016 | 9.50 | 44.00 | Average / 2 | | 9.50 | | | 44.00 | |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-120 (Elec) | Electric | Vertically Integrated | 11/18/2016 | 10.00 | 52.20 | Above Average / 2 | 10.00 | | | 52.20 | | |
| Florida | Florida Power & Light Co. | D-160021-EI | Electric | Vertically Integrated | 11/29/2016 | 10.55 | NA | Above Average / 3 | 10.55 | | | NA | | |
| California | Lbrty Utilities (CalPeco Elect | A-15-05-008 | Electric | Vertically Integrated | 12/1/2016 | 10.00 | 52.50 | Average / 1 | 10.00 | | | 52.50 | | |
| South Carolina | Duke Energy Progress LLC | D-2016-227-E | Electric | Vertically Integrated | 12/7/2016 | 10.10 | 53.00 | Average / 1 | 10.10 | | | 53.00 | | |
| Colorado | Black Hills Colorado Electric | D-16AL-0326E | Electric | Vertically Integrated | 12/19/2016 | 9.37 | 52.39 | Average / 1 | 9.37 | | | 52.39 | | |
| Nevada | Sierra Pacific Power Co. | D-16-06006 | Electric | Vertically Integrated | 12/22/2016 | 9.60 | 48.03 | Average / 2 | | 9.60 | | | 48.03 | |
| North Carolina | Virginia Electric & Power Co. | D-E-22, Sub 532 | Electric | Vertically Integrated | 12/22/2016 | 9.90 | 51.75 | Average / 1 | 9.90 | | | 51.75 | | |
| Idaho | Avista Corp. | C-AVU-E-16-03 | Electric | Vertically Integrated | 12/28/2016 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Wyoming | MDU Resources Group Inc. | D-20004-117-ER-16 | Electric | Vertically Integrated | 1/18/2017 | 9.45 | 50.99 | Average / 2 | | 9.45 | | | 50.99 | |
| Michigan | DTE Electric Co. | C-U-18014 | Electric | Vertically Integrated | 1/31/2017 | 10.10 | NA | Average / 1 | 10.10 | | | NA | | |
| Arizona | Tucson Electric Power Co. | D-E-01933A-15-0322 | Electric | Vertically Integrated | 2/24/2017 | 9.75 | 50.03 | Average / 3 | | | 9.75 | | | 50.03 |
| Michigan | Consumers Energy Co. | C-U-17990 | Electric | Vertically Integrated | 2/28/2017 | 10.10 | NA | Average / 1 | 10.10 | | | NA | | |
| Minnesota | Otter Tail Power Co. | D-E-017/GR-15-1033 | Electric | Vertically Integrated | 3/2/2017 | 9.41 | 52.50 | Average / 2 | | 9.41 | | | 52.50 | |
| Oklahoma | Oklahoma Gas and Electric Co. | Ca-PUD201500273 | Electric | Vertically Integrated | 3/20/2017 | 9.50 | 53.31 | Average / 2 | | 9.50 | | | 53.31 | |
| Florida | Gulf Power Co. | D-160186-EI | Electric | Vertically Integrated | 4/4/2017 | 10.25 | NA | Above Average / 3 | 10.25 | | | NA | | |
| Missouri | Kansas City Power & Light | C-ER-2016-0285 | Electric | Vertically Integrated | 5/3/2017 | 9.50 | 49.20 | Average / 2 | | 9.50 | | | 49.20 | |
| Minnesota | Northern States Power Co. - MN | D-E-002/GR-15-826 | Electric | Vertically Integrated | 5/11/2017 | 9.20 | 52.50 | Average / 2 | | 9.20 | | | 52.50 | |
| Arkansas | Oklahoma Gas and Electric Co. | D-16-052-U | Electric | Vertically Integrated | 5/18/2017 | 9.50 | NA | Average / 1 | 9.50 | | | NA | | |
| North Dakota | MDU Resources Group Inc. | C-PU-16-666 | Electric | Vertically Integrated | 6/16/2017 | 9.65 | 51.40 | Average / 1 | 9.65 | | | 51.40 | | |
| Kentucky | Kentucky Utilities Co. | C-2016-00370 | Electric | Vertically Integrated | 6/22/2017 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| Kentucky | Louisville Gas & Electric Co. | C-2016-00371 (elec.) | Electric | Vertically Integrated | 6/22/2017 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| Arizona | Arizona Public Service Co. | D-E-01345A-16-0036 | Electric | Vertically Integrated | 8/15/2017 | 10.00 | 55.80 | Average / 3 | | | 10.00 | | | 55.80 |
| California | San Diego Gas & Electric Co. | Advice No. 3120-E | Electric | Vertically Integrated | 10/26/2017 | 10.20 | 52.00 | Above Average / 3 | 10.20 | | | 52.00 | | |
| California | Pacific Gas and Electric Co. | Advise No. 3887-G/5148-E | Electric | Vertically Integrated | 10/26/2017 | 10.25 | 52.00 | Above Average / 3 | 10.25 | | | 52.00 | | |
| California | Southern California Edison Co. | Advice No. 3665-E | Electric | Vertically Integrated | 10/26/2017 | 10.30 | 48.00 | Above Average / 3 | 10.30 | | | 48.00 | | |
| Florida | Tampa Electric Co. | D-20170210-EI | Electric | Vertically Integrated | 11/6/2017 | 10.25 | NA | Above Average / 2 | 10.25 | | | NA | | |
| Alaska | Alaska Electric Light Power | D-U-16-086 | Electric | Vertically Integrated | 11/15/2017 | 11.95 | 58.18 | Below Average / 1 | | | 11.95 | | | 58.18 |
| Washington | Puget Sound Energy Inc. | D-UE-170033 | Electric | Vertically Integrated | 12/5/2017 | 9.50 | 48.50 | Average / 3 | | | 9.50 | | | 48.50 |
| Wisconsin | Northern States Power Co - WI | D-4220-UR-123 (Elec) | Electric | Vertically Integrated | 12/7/2017 | 9.80 | 51.45 | Above Average / 2 | 9.80 | | | 51.45 | | |
| Texas | Southwestern Electric Power Co | D-46449 | Electric | Vertically Integrated | 12/14/2017 | 9.60 | 48.46 | Average / 3 | | | 9.60 | | | 48.46 |
| Texas | El Paso Electric Co. | D-46831 | Electric | Vertically Integrated | 12/14/2017 | 9.65 | 48.35 | Average / 3 | | | 9.65 | | | 48.35 |
| Oregon | Portland General Electric Co. | D-UE-319 | Electric | Vertically Integrated | 12/18/2017 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| New Mexico | Public Service Co. of NM | C-16-00276-UT | Electric | Vertically Integrated | 12/20/2017 | 9.58 | 49.61 | Below Average / 2 | | | 9.58 | | | 49.61 |
| Vermont | Green Mountain Power Corp. | C-17-3112-INV | Electric | Vertically Integrated | 12/21/2017 | 9.10 | 48.60 | Average / 2 | | 9.10 | | | 48.60 | |
| Idaho | Avista Corp. | C-AVU-E-17-01 | Electric | Vertically Integrated | 12/28/2017 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Nevada | Nevada Power Co. | D-17-06003 | Electric | Vertically Integrated | 12/29/2017 | 9.51 | 49.99 | Average / 2 | | 9.51 | | | 49.99 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | Equity Ratio (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Kentucky | Kentucky Power Co. | C-2017-00179 | Electric | Vertically Integrated | 1/18/2018 | 9.70 | 41.68 | Average / 1 | 9.70 | | | 41.68 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201700151 | Electric | Vertically Integrated | 1/31/2018 | 9.30 | 48.51 | Average / 3 | | | 9.30 | | | 48.51 |
| Iowa | Interstate Power & Light Co. | D-RPU-2017-0001 | Electric | Vertically Integrated | 2/2/2018 | 9.98 | 49.02 | Average / 1 | 9.98 | | | 49.02 | | |
| North Carolina | Duke Energy Progress LLC | D-E-2, Sub 1142 | Electric | Vertically Integrated | 2/23/2018 | 9.90 | 52.00 | Average / 1 | 9.90 | | | 52.00 | | |
| Minnesota | ALLETE (Minnesota Power) | D-E-015/GR-16-664 | Electric | Vertically Integrated | 3/12/2018 | 9.25 | 53.81 | Average / 2 | | 9.25 | | | 53.81 | |
| Michigan | Consumers Energy Co. | C-U-18322 | Electric | Vertically Integrated | 3/29/2018 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| Michigan | Indiana Michigan Power Co. | C-U-18370 | Electric | Vertically Integrated | 4/12/2018 | 9.90 | NA | Above Average / 3 | 9.90 | | | NA | | |
| Kentucky | Duke Energy Kentucky Inc. | C-2017-00321 | Electric | Vertically Integrated | 4/13/2018 | 9.73 | 49.25 | Average / 1 | 9.73 | | | 49.25 | | |
| Michigan | DTE Electric Co. | C-U-18255 | Electric | Vertically Integrated | 4/18/2018 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| Washington | Avista Corp. | D-UE-170485 | Electric | Vertically Integrated | 4/26/2018 | 9.50 | 48.50 | Average / 3 | | | 9.50 | | | 48.50 |
| Indiana | Indiana Michigan Power Co. | Ca-44967 | Electric | Vertically Integrated | 5/30/2018 | 9.95 | NA | Average / 1 | 9.95 | | | NA | | |
| Hawaii | Hawaiian Electric Co. | D-2016-0328 | Electric | Vertically Integrated | 6/22/2018 | 9.50 | 57.10 | Average / 2 | | 9.50 | | | 57.10 | |
| North Carolina | Duke Energy Carolinas LLC | D-E-7, Sub 1146 | Electric | Vertically Integrated | 6/22/2018 | 9.90 | 52.00 | Average / 1 | 9.90 | | | 52.00 | | |
| Hawaii | Hawaii Electric Light Co | D-2015-0170 | Electric | Vertically Integrated | 6/29/2018 | 9.50 | 56.69 | Average / 2 | | 9.50 | | | 56.69 | |
| New Mexico | Southwestern Public Service Co | C-17-00255-UT | Electric | Vertically Integrated | 9/5/2018 | 9.56 | 53.97 | Below Average / 2 | | | 9.56 | | | 53.97 |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-121 (Elec) | Electric | Vertically Integrated | 9/14/2018 | 10.00 | 52.00 | Above Average / 2 | 10.00 | | | 52.00 | | |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-122 (Elec) | Electric | Vertically Integrated | 9/20/2018 | 9.80 | 56.06 | Above Average / 2 | 9.80 | | | 56.06 | | |
| North Dakota | Otter Tail Power Co. | C-PU-17-398 | Electric | Vertically Integrated | 9/26/2018 | 9.77 | 52.50 | Average / 1 | 9.77 | | | 52.50 | | |
| Kansas | Westar Energy Inc. | D-18-WSEE-328-RTS | Electric | Vertically Integrated | 9/27/2018 | 9.30 | 51.24 | Below Average / 1 | | | 9.30 | | | 51.24 |
| Indiana | Indianapolis Power & Light Co. | Ca-45029 | Electric | Vertically Integrated | 10/31/2018 | 9.99 | NA | Average / 1 | 9.99 | | | NA | | |
| Kansas | Kansas City Power & Light | D-18-KCPE-480-RTS | Electric | Vertically Integrated | 12/13/2018 | 9.30 | 49.09 | Below Average / 1 | | | 9.30 | | | 49.09 |
| Oregon | Portland General Electric Co. | D-UE-335 | Electric | Vertically Integrated | 12/14/2018 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Vermont | Green Mountain Power Corp. | C-18-0974-TF | Electric | Vertically Integrated | 12/21/2018 | 9.30 | 49.85 | Average / 3 | | | 9.30 | | | 49.85 |
| Michigan | Consumers Energy Co. | C-U-20134 | Electric | Vertically Integrated | 1/9/2019 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| West Virginia | Appalachian Power Co. | C-18-0646-E-42T | Electric | Vertically Integrated | 2/27/2019 | 9.75 | 50.16 | Below Average / 2 | | | 9.75 | | | 50.16 |
| Oklahoma | Public Service Co. of OK | Ca-PUD201800097 | Electric | Vertically Integrated | 3/14/2019 | 9.40 | NA | Average / 3 | | | 9.40 | | | NA |
| Kentucky | Kentucky Utilities Co. | C-2018-00294 | Electric | Vertically Integrated | 4/30/2019 | 9.73 | NA | Average / 1 | 9.73 | | | NA | | |
| Kentucky | Louisville Gas & Electric Co. | C-2018-00295 (elec.) | Electric | Vertically Integrated | 4/30/2019 | 9.73 | NA | Average / 1 | 9.73 | | | NA | | |
| South Carolina | Duke Energy Carolinas LLC | D-2018-319-E | Electric | Vertically Integrated | 5/1/2019 | 9.50 | 53.00 | Average / 3 | | | 9.50 | | | 53.00 |
| Michigan | DTE Electric Co. | C-U-20162 | Electric | Vertically Integrated | 5/2/2019 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| South Carolina | Duke Energy Progress LLC | D-2018-318-E | Electric | Vertically Integrated | 5/8/2019 | 9.50 | 53.00 | Average / 3 | | | 9.50 | | | 53.00 |
| South Dakota | Otter Tail Power Co. | D-EL18-021 | Electric | Vertically Integrated | 5/14/2019 | 8.75 | 52.92 | Average / 2 | | 8.75 | | | 52.92 | |
| Hawaii | Maui Electric Company Ltd | D-2017-0150 | Electric | Vertically Integrated | 5/16/2019 | 9.50 | 57.02 | Average / 2 | | 9.50 | | | 57.02 | |
| Michigan | Upper Peninsula Power Co. | C-U-20276 | Electric | Vertically Integrated | 5/23/2019 | 9.90 | NA | Above Average / 3 | 9.90 | | | NA | | |
| Vermont | Green Mountain Power Corp. | C-19-1932-TF | Electric | Vertically Integrated | 8/29/2019 | 9.06 | 49.46 | Average / 3 | | | 9.06 | | | 49.46 |
| Wisconsin | Northern States Power Co - WI | D- 4220-UR-124 (Elec) | Electric | Vertically Integrated | 9/4/2019 | 10.00 | 52.52 | Above Average / 2 | 10.00 | | | 52.52 | | |
| Wisconsin | Wisconsin Electric Power Co. | D-05-UR-109 (WEP-Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | 54.46 | Above Average / 2 | 10.00 | | | 54.46 | | |
| Wisconsin | Wisconsin Public Service Corp. | D-6690-UR-126 (Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | 51.96 | Above Average / 2 | 10.00 | | | 51.96 | | |
| Louisiana - NOCC | Entergy New Orleans LLC | D-UD-18-07 (elec.) | Electric | Vertically Integrated | 11/7/2019 | 9.35 | 50.00 | Average / 2 | | 9.35 | | | 50.00 | |
| Idaho | Avista Corp. | C-AVU-E-1904 | Electric | Vertically Integrated | 11/29/2019 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Indiana | Northern IN Public Svc Co. | Ca-45159 | Electric | Vertically Integrated | 12/4/2019 | 9.75 | NA | Average / 1 | 9.75 | | | NA | | |
| Georgia | Georgia Power Co. | D-42516 | Electric | Vertically Integrated | 12/17/2019 | 10.50 | 56.00 | Above Average / 2 | 10.50 | | | 56.00 | | |
| California | San Diego Gas & Electric Co. | A-19-04-017 (Elec) | Electric | Vertically Integrated | 12/19/2019 | 10.20 | 52.00 | Average / 2 | | 10.20 | | | 52.00 | |
| California | Pacific Gas and Electric Co. | A-19-04-015 | Electric | Vertically Integrated | 12/19/2019 | 10.25 | 52.00 | Average / 2 | | 10.25 | | | 52.00 | |
| California | Southern California Edison Co. | A-19-04-014 | Electric | Vertically Integrated | 12/19/2019 | 10.30 | 52.00 | Average / 2 | | 10.30 | | | 52.00 | |
| Arkansas | Southwestern Electric Power Co | D-19-008-U | Electric | Vertically Integrated | 12/20/2019 | 9.45 | NA | Average / 1 | 9.45 | | | NA | | |
| Montana | NorthWestern Corp. | D2018.2.12 | Electric | Vertically Integrated | 12/20/2019 | 9.65 | 49.38 | Below Average / 1 | | | 9.65 | | | 49.38 |
| Nevada | Sierra Pacific Power Co. | D-19-06002 | Electric | Vertically Integrated | 12/24/2019 | 9.50 | 50.92 | Average / 2 | | 9.50 | | | 50.92 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | Equity Ratio (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Iowa | Interstate Power & Light Co. | D-RPU-2019-0001 | Electric | Vertically Integrated | 1/8/2020 | 10.02 | 51.00 | Average / 1 | 10.02 | | | 51.00 | | |
| Michigan | Indiana Michigan Power Co. | C-U-20359 | Electric | Vertically Integrated | 1/23/2020 | 9.86 | NA | Above Average / 3 | 9.86 | | | NA | | |
| California | PacifiCorp | A-18-04-002 | Electric | Vertically Integrated | 2/6/2020 | 10.00 | 51.96 | Average / 2 | | 10.00 | | | 51.96 | |
| Colorado | Public Service Co. of CO | D-19AL-0268E | Electric | Vertically Integrated | 2/11/2020 | 9.30 | 55.61 | Average / 2 | | 9.30 | | | 55.61 | |
| North Carolina | Virginia Electric & Power Co. | E-22, Sub 562 | Electric | Vertically Integrated | 2/24/2020 | 9.75 | 52.00 | Average / 1 | 9.75 | | | 52.00 | | |
| Indiana | Indiana Michigan Power Co. | Ca-45235 | Electric | Vertically Integrated | 3/11/2020 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| Washington | Avista Corp. | D-UE-190334 | Electric | Vertically Integrated | 3/25/2020 | 9.40 | 48.50 | Average / 3 | | | 9.40 | | | 48.50 |
| Kentucky | Duke Energy Kentucky Inc. | C-2019-00271 | Electric | Vertically Integrated | 4/27/2020 | 9.25 | 48.23 | Average / 1 | 9.25 | | | 48.23 | | |
| Michigan | DTE Electric Co. | C-U-20561 | Electric | Vertically Integrated | 5/8/2020 | 9.90 | NA | Above Average / 3 | 9.90 | | | NA | | |
| New Mexico | Southwestern Public Service Co | C-19-00170-UT | Electric | Vertically Integrated | 5/20/2020 | 9.45 | 54.77 | Below Average / 2 | | | 9.45 | | | 54.77 |
| Indiana | Duke Energy Indiana, LLC | Ca-45253 | Electric | Vertically Integrated | 6/29/2020 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| | | | | | Total Cases | 107 | | | 54 | 26 | 27 | 27 | 26 | 25 |
| | | | | | Mean | 9.74 | 51.20 | | 9.91 | 9.53 | 9.60 | 51.29 | 51.58 | 50.71 |
| | | | | | Median | 9.70 | 51.43 | | 9.90 | 9.50 | 9.50 | 52.00 | 51.48 | 49.61 |
| | | | | | Maximum | 11.95 | 58.18 | | 10.55 | 10.30 | 11.95 | 57.16 | 57.10 | 58.18 |
| | | | | | Minimum | 8.75 | 40.25 | | 9.25 | 8.75 | 9.06 | 40.25 | 44.00 | 48.35 |
| | | | | | # >=9.60% | 63 | | | | | | | | |

Source: Regulatory Research Associates
Note: Authorized equity ratios from Arkansas, Florida, Indiana, and Michigan have been excluded from the equity ratio analysis

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $57.07 | 4.33% | 4.46% | NA | 7.00% | 5.50% | 6.25% | 9.95% | 10.71% | 11.48% |
| Alliant Energy Corporation | LNT | $1.52 | $48.56 | 3.13% | 3.22% | 5.50% | 5.30% | 6.50% | 5.77% | 8.51% | 8.99% | 9.73% |
| Ameren Corporation | AEE | $1.98 | $72.11 | 2.75% | 2.83% | 6.80% | 5.90% | 6.00% | 6.23% | 8.73% | 9.06% | 9.64% |
| American Electric Power Company, Inc. | AEP | $2.80 | $82.01 | 3.41% | 3.51% | 5.80% | 5.88% | 5.00% | 5.56% | 8.50% | 9.07% | 9.39% |
| Avangrid, Inc. | AGR | $1.76 | $42.83 | 4.11% | 4.23% | 5.50% | 6.40% | 6.00% | 5.97% | 9.72% | 10.20% | 10.64% |
| Avista Corporation | AVA | $1.62 | $37.52 | 4.32% | 4.41% | 5.20% | 6.00% | 1.00% | 4.07% | 5.34% | 8.47% | 10.45% |
| CMS Energy Corporation | CMS | $1.63 | $58.02 | 2.81% | 2.91% | 6.90% | 7.16% | 7.50% | 7.19% | 9.81% | 10.10% | 10.41% |
| DTE Energy Company | DTE | $4.05 | $107.49 | 3.77% | 3.87% | 5.50% | 5.84% | 5.00% | 5.45% | 8.86% | 9.32% | 9.72% |
| Evergy, Inc | EVRG | $2.02 | $60.72 | 3.33% | 3.39% | 5.00% | 3.90% | 3.00% | 3.97% | 6.38% | 7.36% | 8.41% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $37.59 | 3.51% | 3.56% | 1.70% | 3.30% | 3.50% | 2.83% | 5.24% | 6.39% | 7.07% |
| NextEra Energy, Inc. | NEE | $5.60 | $246.01 | 2.28% | 2.37% | 7.80% | 8.07% | 10.00% | 8.62% | 10.17% | 11.00% | 12.39% |
| NorthWestern Corporation | NWE | $2.40 | $57.60 | 4.17% | 4.23% | 3.40% | 3.70% | 2.50% | 3.20% | 6.72% | 7.43% | 7.94% |
| OGE Energy Corp. | OGE | $1.55 | $31.40 | 4.94% | 5.01% | 3.70% | 2.40% | 3.00% | 3.03% | 7.40% | 8.04% | 8.73% |
| Otter Tail Corporation | OTTR | $1.48 | $40.68 | 3.64% | 3.75% | NA | 9.00% | 3.50% | 6.25% | 7.20% | 10.00% | 12.80% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $75.46 | 4.15% | 4.25% | 5.20% | 4.48% | 4.50% | 4.73% | 8.72% | 8.97% | 9.46% |
| PNM Resources, Inc. | PNM | $1.23 | $39.47 | 3.12% | 3.21% | 6.10% | 5.65% | 6.00% | 5.92% | 8.85% | 9.12% | 9.31% |
| Portland General Electric Company | POR | $1.54 | $44.55 | 3.46% | 3.53% | 5.30% | 4.15% | 4.00% | 4.48% | 7.53% | 8.02% | 8.85% |
| Southern Company | SO | $2.56 | $55.56 | 4.61% | 4.70% | 4.00% | 4.52% | 3.00% | 3.84% | 7.68% | 8.54% | 9.23% |
| WEC Energy Group, Inc. | WEC | $2.53 | $89.55 | 2.83% | 2.91% | 5.90% | 5.90% | 6.00% | 5.93% | 8.81% | 8.84% | 8.91% |
| Xcel Energy Inc. | XEL | $1.72 | $63.77 | 2.70% | 2.78% | 5.90% | 6.00% | 6.00% | 5.97% | 8.68% | 8.74% | 8.78% |
| PROXY GROUP MEAN | | | | 3.57% | 3.66% | 5.29% | 5.53% | 4.88% | 5.26% | 8.14% | 8.92% | 9.67% |
| PROXY GROUP MEDIAN | | | | 3.48% | 3.55% | 5.50% | 5.86% | 5.00% | 5.66% | 8.60% | 8.98% | 9.42% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of June 30, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $59.85 | 4.13% | 4.26% | NA | 7.00% | 5.50% | 6.25% | 9.74% | 10.51% | 11.27% |
| Alliant Energy Corporation | LNT | $1.52 | $49.41 | 3.08% | 3.16% | 5.50% | 5.30% | 6.50% | 5.77% | 8.46% | 8.93% | 9.68% |
| Ameren Corporation | AEE | $1.98 | $73.85 | 2.68% | 2.76% | 6.80% | 5.90% | 6.00% | 6.23% | 8.66% | 9.00% | 9.57% |
| American Electric Power Company, Inc. | AEP | $2.80 | $83.47 | 3.35% | 3.45% | 5.80% | 5.88% | 5.00% | 5.56% | 8.44% | 9.01% | 9.33% |
| Avangrid, Inc. | AGR | $1.76 | $44.31 | 3.97% | 4.09% | 5.50% | 6.40% | 6.00% | 5.97% | 9.58% | 10.06% | 10.50% |
| Avista Corporation | AVA | $1.62 | $41.52 | 3.90% | 3.98% | 5.20% | 6.00% | 1.00% | 4.07% | 4.92% | 8.05% | 10.02% |
| CMS Energy Corporation | CMS | $1.63 | $58.87 | 2.77% | 2.87% | 6.90% | 7.16% | 7.50% | 7.19% | 9.76% | 10.05% | 10.37% |
| DTE Energy Company | DTE | $4.05 | $103.46 | 3.91% | 4.02% | 5.50% | 5.84% | 5.00% | 5.45% | 9.01% | 9.47% | 9.87% |
| Evergy, Inc | EVRG | $2.02 | $59.79 | 3.38% | 3.45% | 5.00% | 3.90% | 3.00% | 3.97% | 6.43% | 7.41% | 8.46% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $40.34 | 3.27% | 3.32% | 1.70% | 3.30% | 3.50% | 2.83% | 5.00% | 6.15% | 6.83% |
| NextEra Energy, Inc. | NEE | $5.60 | $239.32 | 2.34% | 2.44% | 7.80% | 8.07% | 10.00% | 8.62% | 10.23% | 11.06% | 12.46% |
| NorthWestern Corporation | NWE | $2.40 | $60.34 | 3.98% | 4.04% | 3.40% | 3.70% | 2.50% | 3.20% | 6.53% | 7.24% | 7.75% |
| OGE Energy Corp. | OGE | $1.55 | $31.87 | 4.86% | 4.94% | 3.70% | 2.40% | 3.00% | 3.03% | 7.32% | 7.97% | 8.65% |
| Otter Tail Corporation | OTTR | $1.48 | $42.98 | 3.44% | 3.55% | NA | 9.00% | 3.50% | 6.25% | 7.00% | 9.80% | 12.60% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $78.10 | 4.01% | 4.10% | 5.20% | 4.48% | 4.50% | 4.73% | 8.58% | 8.83% | 9.31% |
| PNM Resources, Inc. | PNM | $1.23 | $40.77 | 3.02% | 3.11% | 6.10% | 5.65% | 6.00% | 5.92% | 8.75% | 9.02% | 9.21% |
| Portland General Electric Company | POR | $1.54 | $47.53 | 3.24% | 3.31% | 5.30% | 4.15% | 4.00% | 4.48% | 7.30% | 7.80% | 8.63% |
| Southern Company | SO | $2.56 | $56.31 | 4.55% | 4.63% | 4.00% | 4.52% | 3.00% | 3.84% | 7.61% | 8.47% | 9.17% |
| WEC Energy Group, Inc. | WEC | $2.53 | $91.42 | 2.77% | 2.85% | 5.90% | 5.90% | 6.00% | 5.93% | 8.75% | 8.78% | 8.85% |
| Xcel Energy Inc. | XEL | $1.72 | $62.99 | 2.73% | 2.81% | 5.90% | 6.00% | 6.00% | 5.97% | 8.71% | 8.78% | 8.81% |
| PROXY GROUP MEAN | | | | 3.47% | 3.56% | 5.29% | 5.53% | 4.88% | 5.26% | 8.04% | 8.82% | 9.57% |
| PROXY GROUP MEDIAN | | | | 3.37% | 3.45% | 5.50% | 5.86% | 5.00% | 5.66% | 8.52% | 8.88% | 9.32% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of June 30, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $70.98 | 3.48% | 3.59% | NA | 7.00% | 5.50% | 6.25% | 9.08% | 9.84% | 10.60% |
| Alliant Energy Corporation | LNT | $1.52 | $52.11 | 2.92% | 3.00% | 5.50% | 5.30% | 6.50% | 5.77% | 8.29% | 8.77% | 9.51% |
| Ameren Corporation | AEE | $1.98 | $75.79 | 2.61% | 2.69% | 6.80% | 5.90% | 6.00% | 6.23% | 8.59% | 8.93% | 9.50% |
| American Electric Power Company, Inc. | AEP | $2.80 | $89.34 | 3.13% | 3.22% | 5.80% | 5.88% | 5.00% | 5.56% | 8.21% | 8.78% | 9.11% |
| Avangrid, Inc. | AGR | $1.76 | $47.51 | 3.70% | 3.82% | 5.50% | 6.40% | 6.00% | 5.97% | 9.31% | 9.78% | 10.22% |
| Avista Corporation | AVA | $1.62 | $44.96 | 3.60% | 3.68% | 5.20% | 6.00% | 1.00% | 4.07% | 4.62% | 7.74% | 9.71% |
| CMS Energy Corporation | CMS | $1.63 | $61.26 | 2.66% | 2.76% | 6.90% | 7.16% | 7.50% | 7.19% | 9.65% | 9.94% | 10.26% |
| DTE Energy Company | DTE | $4.05 | $115.97 | 3.49% | 3.59% | 5.50% | 5.84% | 5.00% | 5.45% | 8.58% | 9.03% | 9.43% |
| Evergy, Inc | EVRG | $2.02 | $62.79 | 3.22% | 3.28% | 5.00% | 3.90% | 3.00% | 3.97% | 6.27% | 7.25% | 8.30% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $43.17 | 3.06% | 3.10% | 1.70% | 3.30% | 3.50% | 2.83% | 4.78% | 5.93% | 6.61% |
| NextEra Energy, Inc. | NEE | $5.60 | $241.87 | 2.32% | 2.42% | 7.80% | 8.07% | 10.00% | 8.62% | 10.21% | 11.04% | 12.43% |
| NorthWestern Corporation | NWE | $2.40 | $66.72 | 3.60% | 3.65% | 3.40% | 3.70% | 2.50% | 3.20% | 6.14% | 6.85% | 7.36% |
| OGE Energy Corp. | OGE | $1.55 | $37.90 | 4.09% | 4.15% | 3.70% | 2.40% | 3.00% | 3.03% | 6.54% | 7.19% | 7.87% |
| Otter Tail Corporation | OTTR | $1.48 | $47.68 | 3.10% | 3.20% | NA | 9.00% | 3.50% | 6.25% | 6.66% | 9.45% | 12.24% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $84.95 | 3.68% | 3.77% | 5.20% | 4.48% | 4.50% | 4.73% | 8.25% | 8.50% | 8.98% |
| PNM Resources, Inc. | PNM | $1.23 | $45.91 | 2.68% | 2.76% | 6.10% | 5.65% | 6.00% | 5.92% | 8.40% | 8.67% | 8.86% |
| Portland General Electric Company | POR | $1.54 | $52.38 | 2.94% | 3.01% | 5.30% | 4.15% | 4.00% | 4.48% | 7.00% | 7.49% | 8.32% |
| Southern Company | SO | $2.56 | $60.23 | 4.25% | 4.33% | 4.00% | 4.52% | 3.00% | 3.84% | 7.31% | 8.17% | 8.87% |
| WEC Energy Group, Inc. | WEC | $2.53 | $92.38 | 2.74% | 2.82% | 5.90% | 5.90% | 6.00% | 5.93% | 8.72% | 8.75% | 8.82% |
| Xcel Energy Inc. | XEL | $1.72 | $63.55 | 2.71% | 2.79% | 5.90% | 6.00% | 6.00% | 5.97% | 8.69% | 8.75% | 8.79% |
| PROXY GROUP MEAN | | | | 3.20% | 3.28% | 5.29% | 5.53% | 4.88% | 5.26% | 7.76% | 8.54% | 9.29% |
| PROXY GROUP MEDIAN | | | | 3.12% | 3.21% | 5.50% | 5.86% | 5.00% | 5.66% | 8.27% | 8.75% | 9.04% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of June 30, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 13.21% | 1.47% | 11.73% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 27,286.66 | 0.10% | 0.80% | 10.30% | 11.14% | 0.0112% |
| American Airlines Group Inc | AAL | 6,640.99 | 0.02% | 0.77% | -19.74% | -19.05% | -0.0047% |
| Advance Auto Parts Inc | AAP | 9,843.47 | 0.04% | 0.58% | 10.47% | 11.07% | 0.0040% |
| Apple Inc | AAPL | 1,581,165.41 | 5.83% | 0.88% | 11.00% | 11.93% | 0.6958% |
| AbbVie Inc | ABBV | 173,027.92 | 0.64% | 4.79% | 3.15% | 8.01% | 0.0511% |
| AmerisourceBergen Corp | ABC | 20,496.90 | 0.08% | 1.67% | 4.17% | 5.86% | 0.0044% |
| ABIOMED Inc | ABMD | 10,859.80 | N/A | 0.00% | N/A | N/A | N/A |
| Abbott Laboratories | ABT | 161,725.53 | 0.60% | 1.58% | 8.10% | 9.74% | 0.0581% |
| Accenture PLC | ACN | 136,810.19 | 0.50% | 1.49% | 9.83% | 11.40% | 0.0575% |
| Adobe Inc | ADBE | 208,803.08 | 0.77% | 0.00% | 16.35% | 16.35% | 0.1259% |
| Analog Devices Inc | ADI | 45,183.59 | 0.17% | 1.95% | 12.13% | 14.19% | 0.0236% |
| Archer-Daniels-Midland Cc | ADM | 22,164.30 | 0.08% | 3.63% | 9.10% | 12.89% | 0.0105% |
| Automatic Data Processing Inc | ADP | 63,989.11 | 0.24% | 2.35% | 12.30% | 14.80% | 0.0349% |
| Autodesk Inc | ADSK | 52,429.66 | 0.19% | 0.00% | 31.35% | 31.35% | 0.0606% |
| Ameren Corp | AEE | 17,360.43 | 0.06% | 2.86% | 7.06% | 10.02% | 0.0064% |
| American Electric Power Co Inc | AEP | 39,468.24 | 0.15% | 3.55% | 6.42% | 10.08% | 0.0147% |
| AES Corp/The | AES | 9,634.51 | 0.04% | 4.00% | 6.99% | 11.14% | 0.0040% |
| Aflac Inc | AFL | 25,851.81 | 0.10% | 3.14% | 1.55% | 4.71% | 0.0045% |
| American International Group Inc | AIG | 26,855.04 | 0.10% | 4.13% | 13.57% | 17.98% | 0.0178% |
| Apartment Investment and Management Cc | AIV | 5,603.25 | 0.02% | 4.36% | 3.77% | 8.21% | 0.0017% |
| Assurant Inc | AIZ | 6,161.48 | N/A | 2.50% | N/A | N/A | N/A |
| Arthur J Gallagher & Co | AJG | 18,484.10 | 0.07% | 1.84% | 8.88% | 10.80% | 0.0074% |
| Akamai Technologies Inc | AKAM | 17,377.97 | 0.06% | 0.00% | 11.80% | 11.80% | 0.0076% |
| Albemarle Corp | ALB | 8,208.86 | 0.03% | 1.95% | 10.02% | 12.06% | 0.0037% |
| Align Technology Inc | ALGN | 21,615.71 | 0.08% | 0.00% | 12.87% | 12.87% | 0.0103% |
| Alaska Air Group Inc | ALK | 4,444.95 | N/A | 1.05% | N/A | N/A | N/A |
| Allstate Corp/The | ALL | 30,466.12 | 0.11% | 2.17% | 7.33% | 9.58% | 0.0108% |
| Allegion plc | ALLE | 9,426.75 | 0.03% | 0.96% | 6.17% | 7.16% | 0.0025% |
| Alexion Pharmaceuticals Inc | ALXN | 24,785.67 | 0.09% | 0.00% | 11.37% | 11.37% | 0.0104% |
| Applied Materials Inc | AMAT | 55,401.17 | 0.20% | 1.42% | 14.04% | 15.56% | 0.0318% |
| Amcor PLC | AMCR | 16,075.01 | 0.06% | 4.54% | 8.90% | 13.65% | 0.0081% |
| Advanced Micro Devices Inc | AMD | 61,616.33 | 0.23% | 0.00% | 20.33% | 20.33% | 0.0462% |
| AMETEK Inc | AME | 20,504.35 | 0.08% | 0.74% | 9.16% | 9.94% | 0.0075% |
| Amgen Inc | AMGN | 138,744.03 | 0.51% | 2.68% | 7.89% | 10.68% | 0.0546% |
| Ameriprise Financial Inc | AMP | 18,355.48 | 0.07% | 2.74% | 3.90% | 6.70% | 0.0045% |
| American Tower Corp | AMT | 114,612.45 | 0.42% | 1.74% | 15.64% | 17.52% | 0.0740% |
| Amazon.com Inc | AMZN | 1,376,033.29 | 5.07% | 0.00% | 26.48% | 26.48% | 1.3440% |
| Arista Networks Inc | ANET | 15,900.22 | 0.06% | 0.00% | 8.38% | 8.38% | 0.0049% |
| ANSYS Inc | ANSS | 24,970.76 | 0.09% | 0.00% | 11.30% | 11.30% | 0.0104% |
| Anthem Inc | ANTM | 66,301.49 | 0.24% | 1.29% | 12.67% | 14.04% | 0.0343% |
| Aon PLC | AON | 44,506.89 | 0.16% | 0.93% | 11.05% | 12.03% | 0.0198% |
| A O Smith Corp | AOS | 7,592.93 | 0.03% | 2.05% | 8.00% | 10.13% | 0.0028% |
| Apache Corp | APA | 5,095.25 | 0.02% | 2.41% | -26.07% | -23.97% | -0.0045% |
| Air Products and Chemicals Inc | APD | 53,327.56 | 0.20% | 2.07% | 11.69% | 13.88% | 0.0273% |
| Amphenol Corp | APH | 28,349.64 | 0.10% | 1.02% | 8.12% | 9.18% | 0.0096% |
| Aptiv PLC | APTV | 21,038.67 | 0.08% | 0.22% | 10.69% | 10.92% | 0.0085% |
| Alexandria Real Estate Equities Inc | ARE | 20,475.11 | 0.08% | 2.57% | 4.08% | 6.70% | 0.0051% |
| Atmos Energy Corp | ATO | 12,179.78 | 0.04% | 2.31% | 7.51% | 9.90% | 0.0044% |
| Activision Blizzard Inc | ATVI | 58,479.85 | 0.22% | 0.52% | 12.58% | 13.13% | 0.0283% |
| AvalonBay Communities Inc | AVB | 21,762.69 | 0.08% | 4.09% | 3.41% | 7.57% | 0.0061% |
| Broadcom Inc | AVGO | 126,933.70 | 0.47% | 4.12% | 9.37% | 13.68% | 0.0641% |
| Avery Dennison Corp | AVY | 9,508.26 | 0.04% | 2.01% | 4.50% | 6.55% | 0.0023% |
| American Water Works Co Inc | AWK | 23,290.41 | 0.09% | 1.68% | 8.20% | 9.95% | 0.0085% |
| American Express Co | AXP | 76,633.29 | 0.28% | 1.83% | 8.68% | 10.59% | 0.0299% |
| AutoZone Inc | AZO | 26,352.18 | 0.10% | 0.00% | 7.70% | 7.70% | 0.0075% |
| Boeing Co/The | BA | 103,440.84 | 0.38% | 1.12% | 118.28% | 120.07% | 0.4581% |
| Bank of America Corp | BAC | 206,045.76 | 0.76% | 3.09% | 9.25% | 12.49% | 0.0949% |
| Baxter International Inc | BAX | 43,670.44 | 0.16% | 0.92% | 11.00% | 11.97% | 0.0193% |
| Best Buy Co Inc | BBY | 22,542.63 | 0.08% | 2.52% | 4.65% | 7.23% | 0.0060% |
| Becton Dickinson and Cc | BDX | 69,335.77 | 0.26% | 1.47% | 8.14% | 9.66% | 0.0247% |
| Franklin Resources Inc | BEN | 10,386.57 | 0.04% | 5.15% | -3.02% | 2.06% | 0.0008% |
| Brown-Forman Corp | BF/B | 29,415.09 | 0.11% | 1.11% | 4.93% | 6.07% | 0.0066% |
| Biogen Inc | BIIB | 43,660.81 | 0.16% | 0.00% | 1.13% | 1.13% | 0.0018% |
| Bio-Rad Laboratories Inc | BIO | 13,312.07 | 0.05% | 0.00% | 4.00% | 4.00% | 0.0020% |
| Bank of New York Mellon Corp/The | BK | 34,222.37 | 0.13% | 3.24% | 4.43% | 7.74% | 0.0098% |
| Booking Holdings Inc | BKNG | 65,175.93 | 0.24% | 0.00% | 13.20% | 13.20% | 0.0317% |
| Baker Hughes Co | BKR | 15,889.60 | 0.06% | 4.72% | 17.77% | 22.91% | 0.0134% |
| BlackRock Inc | BLK | 83,464.27 | 0.31% | 2.67% | 4.24% | 6.97% | 0.0215% |
| Ball Corp | BLL | 22,653.96 | 0.08% | 0.83% | 6.07% | 6.92% | 0.0058% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Bristol-Myers Squibb Co | BMY | 133,046.16 | 0.49% | 3.06% | 9.90% | 13.11% | 0.0643% |
| Broadridge Financial Solutions Inc | BR | 14,488.82 | 0.05% | 1.71% | 6.50% | 8.27% | 0.0044% |
| Berkshire Hathaway Inc | BRK/B | 433,463.33 | 1.60% | 0.00% | -3.10% | -3.10% | -0.0496% |
| Boston Scientific Corp | BSX | 50,161.43 | 0.19% | 0.00% | 9.75% | 9.75% | 0.0180% |
| BorgWarner Inc | BWA | 7,318.04 | 0.03% | 1.99% | 9.30% | 11.38% | 0.0031% |
| Boston Properties Inc | BXP | 14,042.26 | 0.05% | 4.38% | 3.97% | 8.44% | 0.0044% |
| Citigroup Inc | C | 106,379.98 | 0.39% | 4.00% | -1.53% | 2.44% | 0.0096% |
| Conagra Brands Inc | CAG | 17,130.47 | 0.06% | 2.42% | 7.90% | 10.42% | 0.0066% |
| Cardinal Health Inc | CAH | 15,238.77 | 0.06% | 3.74% | 4.84% | 8.67% | 0.0049% |
| Carrier Global Corp | CARR | 19,246.05 | 0.07% | 0.12% | 4.50% | 4.62% | 0.0033% |
| Caterpillar Inc | CAT | 68,466.77 | 0.25% | 3.34% | 7.83% | 11.31% | 0.0286% |
| Chubb Ltd | CB | 57,150.85 | 0.21% | 2.43% | 9.37% | 11.91% | 0.0251% |
| Cboe Global Markets Inc | CBOE | 10,234.71 | 0.04% | 1.60% | 6.81% | 8.46% | 0.0032% |
| CBRE Group Inc | CBRE | 15,156.24 | 0.06% | 0.00% | 8.45% | 8.45% | 0.0047% |
| Crown Castle International Corp | CCI | 69,743.32 | 0.26% | 2.92% | 17.63% | 20.81% | 0.0535% |
| Carnival Corp | CCL | 11,751.20 | 0.04% | 4.65% | -11.65% | -7.27% | -0.0032% |
| Cadence Design Systems Inc | CDNS | 26,790.78 | 0.10% | 0.00% | 11.09% | 11.09% | 0.0110% |
| CDW Corp/DE | CDW | 16,534.52 | 0.06% | 1.31% | 13.10% | 14.49% | 0.0088% |
| Celanese Corp | CE | 10,207.88 | 0.04% | 2.93% | 3.61% | 6.59% | 0.0025% |
| Cerner Corp | CERN | 20,863.10 | 0.08% | 0.56% | 11.91% | 12.50% | 0.0096% |
| CF Industries Holdings Inc | CF | 6,016.26 | 0.02% | 4.26% | 11.05% | 15.55% | 0.0035% |
| Citizens Financial Group Inc | CFG | 10,767.86 | 0.04% | 6.16% | -0.15% | 6.01% | 0.0024% |
| Church & Dwight Co Inc | CHD | 19,007.51 | 0.07% | 1.25% | 7.87% | 9.16% | 0.0064% |
| CH Robinson Worldwide Inc | CHRW | 10,642.26 | 0.04% | 2.59% | 8.37% | 11.07% | 0.0043% |
| Charter Communications Inc | CHTR | 121,450.42 | 0.45% | 0.00% | 42.98% | 42.98% | 0.1925% |
| Cigna Corp | CI | 69,239.28 | 0.26% | 0.05% | 11.09% | 11.15% | 0.0285% |
| Cincinnati Financial Corp | CINF | 10,296.12 | N/A | 4.04% | N/A | N/A | N/A |
| Colgate-Palmolive Co | CL | 62,749.27 | 0.23% | 2.44% | 5.25% | 7.75% | 0.0179% |
| Clorox Co/The | CLX | 27,626.10 | 0.10% | 1.92% | 5.12% | 7.09% | 0.0072% |
| Comerica Inc | CMA | 5,297.22 | 0.02% | 7.07% | -0.20% | 6.86% | 0.0013% |
| Comcast Corp | CMCSA | 177,910.86 | 0.66% | 2.34% | 5.13% | 7.54% | 0.0495% |
| CME Group Inc | CME | 58,284.94 | 0.21% | 3.69% | 8.39% | 12.23% | 0.0263% |
| Chipotle Mexican Grill Inc | CMG | 29,351.10 | 0.11% | 0.00% | 15.17% | 15.17% | 0.0164% |
| Cummins Inc | CMI | 25,560.37 | 0.09% | 3.09% | 3.26% | 6.40% | 0.0060% |
| CMS Energy Corp | CMS | 16,721.06 | 0.06% | 2.79% | 6.87% | 9.75% | 0.0060% |
| Centene Corp | CNC | 36,803.67 | 0.14% | 0.00% | 13.27% | 13.27% | 0.0180% |
| CenterPoint Energy Inc | CNP | 9,383.82 | 0.03% | 3.83% | -3.49% | 0.28% | 0.0001% |
| Capital One Financial Corp | COF | 28,497.86 | 0.11% | 2.57% | 1.00% | 3.58% | 0.0038% |
| Cabot Oil & Gas Corp | COG | 6,847.53 | 0.03% | 2.33% | 23.75% | 26.36% | 0.0067% |
| Cooper Cos Inc/The | COO | 15,127.40 | 0.06% | 0.02% | 8.03% | 8.05% | 0.0045% |
| ConocoPhillips | COP | 45,063.31 | N/A | 4.01% | N/A | N/A | N/A |
| Costco Wholesale Corp | COST | 133,874.40 | 0.49% | 0.90% | 6.87% | 7.80% | 0.0385% |
| Coty Inc | COTY | 3,411.04 | 0.01% | 8.10% | -1.77% | 6.26% | 0.0008% |
| Campbell Soup Co | CPB | 14,996.42 | 0.06% | 2.85% | 8.89% | 11.87% | 0.0066% |
| Copart Inc | CPRT | 19,549.92 | N/A | 0.00% | N/A | N/A | N/A |
| salesforce.com Inc | CRM | 168,784.33 | 0.62% | 0.00% | 19.08% | 19.08% | 0.1188% |
| Cisco Systems Inc | CSCO | 196,927.89 | 0.73% | 3.04% | 5.50% | 8.63% | 0.0627% |
| CSX Corp | CSX | 53,383.59 | 0.20% | 1.51% | 8.41% | 9.98% | 0.0197% |
| Cintas Corp | CTAS | 27,714.81 | 0.10% | 0.93% | 9.95% | 10.93% | 0.0112% |
| CenturyLink Inc | CTL | 11,007.95 | 0.04% | 9.99% | -1.33% | 8.59% | 0.0035% |
| Cognizant Technology Solutions Corp | CTSH | 30,715.76 | 0.11% | 1.52% | 10.40% | 12.00% | 0.0136% |
| Corteva Inc | CTVA | 20,073.30 | 0.07% | 1.91% | 9.69% | 11.69% | 0.0087% |
| Citrix Systems Inc | CTXS | 18,259.58 | 0.07% | 0.94% | 9.33% | 10.32% | 0.0070% |
| CVS Health Corp | CVS | 84,921.69 | 0.31% | 3.08% | 7.36% | 10.54% | 0.0330% |
| Chevron Corp | CVX | 166,590.50 | 0.61% | 5.99% | 38.90% | 46.06% | 0.2830% |
| Concho Resources Inc | CXO | 10,130.13 | 0.04% | 1.55% | 1.23% | 2.79% | 0.0010% |
| Dominion Energy Inc | D | 68,130.40 | 0.25% | 4.65% | 4.96% | 9.73% | 0.0244% |
| Delta Air Lines Inc | DAL | 17,889.94 | 0.07% | 1.15% | -6.43% | -5.32% | -0.0035% |
| DuPont de Nemours Inc | DD | 38,986.65 | 0.14% | 2.29% | 1.82% | 4.13% | 0.0059% |
| Deere & Co | DE | 49,165.73 | 0.18% | 1.93% | 0.41% | 2.34% | 0.0042% |
| Discover Financial Services | DFS | 15,342.61 | 0.06% | 3.55% | 15.51% | 19.33% | 0.0109% |
| Dollar General Corp | DG | 47,955.53 | 0.18% | 0.76% | 11.63% | 12.42% | 0.0220% |
| Quest Diagnostics Inc | DGX | 15,240.08 | 0.06% | 1.96% | 5.65% | 7.67% | 0.0043% |
| DR Horton Inc | DHI | 20,158.17 | 0.07% | 1.26% | 10.55% | 11.87% | 0.0088% |
| Danaher Corp | DHR | 125,186.12 | 0.46% | 0.40% | 8.52% | 8.94% | 0.0413% |
| Walt Disney Co/The | DIS | 201,416.80 | 0.74% | 0.85% | 4.08% | 4.94% | 0.0367% |
| Discovery Inc | DISCA | 14,585.08 | 0.05% | 0.00% | -3.45% | -3.45% | -0.0019% |
| DISH Network Corp | DISH | 18,088.68 | 0.07% | 0.00% | 1.62% | 1.62% | 0.0011% |
| Digital Realty Trust Inc | DLR | 39,334.12 | 0.15% | 3.16% | 19.70% | 23.17% | 0.0336% |
| Dollar Tree Inc | DLTR | 21,986.70 | 0.08% | 0.00% | 8.86% | 8.86% | 0.0072% |
| Dover Corp | DOV | 13,899.52 | 0.05% | 2.06% | 10.30% | 12.46% | 0.0064% |
| Dow Inc | DOW | 30,271.63 | 0.11% | 6.97% | 2.22% | 9.27% | 0.0103% |
| Domino's Pizza Inc | DPZ | 14,451.71 | 0.05% | 0.84% | 13.16% | 14.05% | 0.0075% |
| Duke Realty Corp | DRE | 13,037.04 | 0.05% | 2.66% | -0.65% | 2.00% | 0.0010% |
| Darden Restaurants Inc | DRI | 9,840.95 | 0.04% | 2.67% | 10.33% | 13.13% | 0.0048% |
| DTE Energy Co | DTE | 20,651.29 | 0.08% | 3.79% | 5.87% | 9.77% | 0.0074% |
| Duke Energy Corp | DUK | 58,719.15 | 0.22% | 4.85% | 4.16% | 9.11% | 0.0197% |
| DaVita Inc | DVA | 9,639.25 | 0.04% | 0.76% | 9.56% | 10.35% | 0.0037% |
| Devon Energy Corp | DVN | 4,339.82 | 0.02% | 3.69% | -9.15% | -5.62% | -0.0009% |
| DXC Technology Co | DXC | 4,186.90 | 0.02% | 1.62% | -17.84% | -16.37% | -0.0025% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| DexCom Inc | DXCM | 37,436.61 | 0.14% | 0.00% | 30.99% | 30.99% | 0.0428% |
| Electronic Arts Inc | EA | 38,124.73 | 0.14% | 0.00% | 8.00% | 8.00% | 0.0112% |
| eBay Inc | EBAY | 36,855.50 | 0.14% | 1.22% | 12.04% | 13.34% | 0.0181% |
| Ecolab Inc | ECL | 57,541.65 | 0.21% | 0.96% | 7.90% | 8.90% | 0.0189% |
| Consolidated Edison Inc | ED | 24,031.96 | 0.09% | 4.24% | 3.35% | 7.66% | 0.0068% |
| Equifax Inc | EFX | 20,863.68 | 0.08% | 0.91% | 7.46% | 8.40% | 0.0065% |
| Edison Internationa | EIX | 20,526.00 | 0.08% | 4.67% | 4.54% | 9.32% | 0.0071% |
| Estee Lauder Cos Inc/The | EL | 67,924.54 | 0.25% | 0.77% | 8.83% | 9.63% | 0.0241% |
| Eastman Chemical Co | EMN | 9,463.68 | 0.03% | 3.78% | 1.92% | 5.73% | 0.0020% |
| Emerson Electric Co | EMR | 37,061.39 | 0.14% | 3.18% | 6.51% | 9.80% | 0.0134% |
| EOG Resources Inc | EOG | 29,486.45 | 0.11% | 2.87% | 1.45% | 4.34% | 0.0047% |
| Equinix Inc | EQIX | 62,163.78 | 0.23% | 1.51% | 18.80% | 20.45% | 0.0469% |
| Equity Residential | EQR | 21,888.43 | 0.08% | 4.06% | 3.41% | 7.54% | 0.0061% |
| Eversource Energy | ES | 28,523.70 | 0.11% | 2.73% | 6.82% | 9.64% | 0.0101% |
| Essex Property Trust Inc | ESS | 14,991.70 | 0.06% | 3.61% | 3.90% | 7.58% | 0.0042% |
| E*TRADE Financial Corp | ETFC | 10,994.77 | 0.04% | 1.15% | -11.58% | -10.49% | -0.0043% |
| Eaton Corp PLC | ETN | 34,992.00 | 0.13% | 3.35% | 9.03% | 12.53% | 0.0162% |
| Entergy Corp | ETR | 18,777.19 | 0.07% | 3.98% | 4.72% | 8.80% | 0.0061% |
| Evergy Inc | EVRG | 13,438.61 | 0.05% | 3.46% | 6.90% | 10.48% | 0.0052% |
| Edwards Lifesciences Corp | EW | 42,825.00 | 0.16% | 0.00% | 13.75% | 13.75% | 0.0217% |
| Exelon Corp | EXC | 35,343.91 | 0.13% | 4.21% | 0.50% | 4.72% | 0.0062% |
| Expeditors International of Washington | EXPD | 12,655.05 | 0.05% | 1.41% | 6.50% | 7.95% | 0.0037% |
| Expedia Group Inc | EXPE | 11,588.79 | 0.04% | 0.41% | 10.00% | 10.44% | 0.0045% |
| Extra Space Storage Inc | EXR | 11,923.73 | 0.04% | 3.92% | 1.50% | 5.45% | 0.0024% |
| Ford Motor Co | F | 24,180.40 | 0.09% | 3.09% | 13.51% | 16.81% | 0.0150% |
| Diamondback Energy Inc | FANG | 6,599.86 | 0.02% | 3.44% | 17.94% | 21.68% | 0.0053% |
| Fastenal Co | FAST | 24,607.13 | 0.09% | 2.34% | 14.45% | 16.96% | 0.0154% |
| Facebook Inc | FB | 647,452.82 | 2.39% | 0.00% | 22.16% | 22.16% | 0.5292% |
| Fortune Brands Home & Security Inc | FBHS | 8,818.95 | 0.03% | 1.50% | 9.35% | 10.93% | 0.0036% |
| Freeport-McMoRan Inc | FCX | 16,799.30 | 0.06% | 0.43% | 136.19% | 136.92% | 0.0848% |
| FedEx Corp | FDX | 36,632.44 | N/A | 1.86% | N/A | N/A | N/A |
| FirstEnergy Corp | FE | 21,009.21 | 0.08% | 4.02% | 0.65% | 4.68% | 0.0036% |
| F5 Networks Inc | FFIV | 8,493.85 | 0.03% | 0.00% | 4.02% | 4.02% | 0.0013% |
| Fidelity National Information Services | FIS | 82,845.34 | 0.31% | 1.07% | 19.58% | 20.75% | 0.0634% |
| Fiserv Inc | FISV | 65,355.06 | 0.24% | 0.00% | 13.86% | 13.86% | 0.0334% |
| Fifth Third Bancorp | FITB | 13,725.66 | 0.05% | 5.59% | 9.77% | 15.64% | 0.0079% |
| FLIR Systems Inc | FLIR | 5,308.27 | N/A | 1.76% | N/A | N/A | N/A |
| Flowserve Corp | FLS | 3,711.19 | 0.01% | 2.81% | 3.00% | 5.85% | 0.0008% |
| FleetCor Technologies Inc | FLT | 21,078.78 | 0.08% | 0.00% | 13.20% | 13.20% | 0.0103% |
| FMC Corp | FMC | 12,895.53 | 0.05% | 1.77% | 9.63% | 11.48% | 0.0055% |
| Fox Corp | FOX | 16,197.01 | 0.06% | 1.71% | -4.08% | -2.40% | -0.0014% |
| First Republic Bank/CA | FRC | 18,154.77 | 0.07% | 0.75% | 9.11% | 9.89% | 0.0066% |
| Federal Realty Investment Trust | FRT | 6,444.69 | 0.02% | 4.94% | 3.16% | 8.18% | 0.0019% |
| TechnipFMC PLC | FTI | 3,066.40 | 0.01% | 2.00% | 9.50% | 11.60% | 0.0013% |
| Fortinet Inc | FTNT | 22,189.50 | 0.08% | 0.00% | 15.10% | 15.10% | 0.0124% |
| Fortive Corp | FTV | 22,791.68 | 0.08% | 0.43% | 8.67% | 9.11% | 0.0077% |
| General Dynamics Corp | GD | 42,874.77 | 0.16% | 2.90% | 4.58% | 7.54% | 0.0119% |
| General Electric Co | GE | 59,742.64 | 0.22% | 0.59% | 6.07% | 6.67% | 0.0147% |
| Gilead Sciences Inc | GILD | 96,511.49 | 0.36% | 3.46% | 0.87% | 4.34% | 0.0155% |
| General Mills Inc | GIS | 37,368.46 | 0.14% | 3.18% | 5.87% | 9.14% | 0.0126% |
| Globe Life Inc | GL | 7,900.89 | 0.03% | 0.97% | 5.06% | 6.05% | 0.0018% |
| Corning Inc | GLW | 19,708.55 | 0.07% | 3.36% | 4.13% | 7.56% | 0.0055% |
| General Motors Co | GM | 36,206.23 | 0.13% | 1.40% | 13.21% | 14.70% | 0.0196% |
| Alphabet Inc | GOOG | 966,394.01 | 3.56% | 0.00% | 14.18% | 14.18% | 0.5055% |
| Genuine Parts Co | GPC | 12,544.87 | 0.05% | 3.60% | 1.82% | 5.45% | 0.0025% |
| Global Payments Inc | GPN | 50,734.31 | 0.19% | 0.40% | 17.45% | 17.89% | 0.0335% |
| Gap Inc/The | GPS | 4,713.20 | 0.02% | 2.44% | 4.47% | 6.96% | 0.0012% |
| Garmin Ltd | GRMN | 18,624.24 | 0.07% | 2.46% | 6.90% | 9.44% | 0.0065% |
| Goldman Sachs Group Inc/The | GS | 70,844.40 | 0.26% | 2.55% | 3.50% | 6.09% | 0.0159% |
| WW Grainger Inc | GWW | 16,797.49 | 0.06% | 1.93% | 9.47% | 11.48% | 0.0071% |
| Halliburton Co | HAL | 11,387.06 | 0.04% | 3.70% | 12.95% | 16.89% | 0.0071% |
| Hasbro Inc | HAS | 10,269.00 | 0.04% | 3.65% | 14.34% | 18.24% | 0.0069% |
| Huntington Bancshares Inc/OH | HBAN | 9,163.46 | 0.03% | 6.66% | -9.27% | -2.92% | -0.0010% |
| Hanesbrands Inc | HBI | 3,929.32 | 0.01% | 4.75% | 0.84% | 5.61% | 0.0008% |
| HCA Healthcare Inc | HCA | 32,769.29 | 0.12% | 0.31% | 8.66% | 8.98% | 0.0109% |
| Home Depot Inc/The | HD | 269,429.23 | 0.99% | 2.34% | 7.47% | 9.89% | 0.0983% |
| Hess Corp | HES | 15,913.13 | 0.06% | 1.97% | -23.46% | -21.72% | -0.0127% |
| HollyFrontier Corp | HFC | 4,727.07 | 0.02% | 4.79% | -2.81% | 1.91% | 0.0003% |
| Hartford Financial Services Group Inc/Th | HIG | 13,803.79 | 0.05% | 3.39% | 9.50% | 13.05% | 0.0066% |
| Huntington Ingalls Industries Inc | HII | 7,062.35 | 0.03% | 2.44% | 40.00% | 42.92% | 0.0112% |
| Hilton Worldwide Holdings Inc | HLT | 20,364.86 | 0.08% | 0.20% | 1.28% | 1.48% | 0.0011% |
| Hologic Inc | HOLX | 14,717.72 | 0.05% | 0.00% | 8.85% | 8.85% | 0.0048% |
| Honeywell International Inc | HON | 101,480.17 | 0.37% | 2.42% | 6.81% | 9.31% | 0.0349% |
| Hewlett Packard Enterprise Co | HPE | 12,500.69 | 0.05% | 4.96% | 2.00% | 7.01% | 0.0032% |
| HP Inc | HPQ | 24,924.15 | 0.09% | 4.04% | 4.77% | 8.91% | 0.0082% |
| H&R Block Inc | HRB | 2,748.55 | 0.01% | 7.28% | 10.00% | 17.65% | 0.0018% |
| Hormel Foods Corp | HRL | 26,015.20 | 0.10% | 1.91% | 0.76% | 2.68% | 0.0026% |
| Henry Schein Inc | HSIC | 8,335.53 | 0.03% | 0.00% | -1.20% | -1.20% | -0.0004% |
| Host Hotels & Resorts Inc | HST | 7,606.51 | 0.03% | 2.51% | -9.60% | -7.21% | -0.0020% |
| Hershey Co/The | HSY | 26,962.21 | 0.10% | 2.48% | 6.83% | 9.40% | 0.0093% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Humana Inc | HUM | 51,262.90 | 0.19% | 0.64% | 11.56% | 12.24% | 0.0231% |
| Howmet Aerospace Inc | HWM | 6,912.24 | 0.03% | 0.13% | 50.90% | 51.06% | 0.0130% |
| International Business Machines Corp | IBM | 107,230.71 | 0.40% | 5.46% | 2.67% | 8.21% | 0.0325% |
| Intercontinental Exchange Inc | ICE | 50,125.52 | 0.18% | 1.30% | 9.16% | 10.51% | 0.0194% |
| IDEXX Laboratories Inc | IDXX | 28,041.47 | 0.10% | 0.00% | 9.41% | 9.41% | 0.0097% |
| IDEX Corp | IEX | 11,914.93 | 0.04% | 1.32% | 11.33% | 12.72% | 0.0056% |
| International Flavors & Fragrances Inc | IFF | 13,084.99 | 0.05% | 2.42% | 4.95% | 7.43% | 0.0036% |
| Illumina Inc | ILMN | 54,441.45 | 0.20% | 0.00% | 18.06% | 18.06% | 0.0363% |
| Incyte Corp | INCY | 22,600.32 | 0.08% | 0.00% | 31.72% | 31.72% | 0.0264% |
| IHS Markit Ltd | INFO | 29,959.13 | 0.11% | 0.72% | 12.15% | 12.91% | 0.0143% |
| Intel Corp | INTC | 253,320.22 | 0.93% | 2.18% | 5.93% | 8.17% | 0.0764% |
| Intuit Inc | INTU | 77,237.86 | 0.28% | 0.71% | 13.20% | 13.95% | 0.0397% |
| International Paper Co | IP | 13,838.98 | 0.05% | 5.83% | 4.40% | 10.36% | 0.0053% |
| Interpublic Group of Cos Inc/The | IPG | 6,685.77 | 0.02% | 5.62% | 0.19% | 5.82% | 0.0014% |
| IPG Photonics Corp | IPGP | 8,505.09 | 0.03% | 0.00% | 23.11% | 23.11% | 0.0072% |
| IQVIA Holdings Inc | IQV | 27,093.94 | 0.10% | 0.00% | 11.20% | 11.20% | 0.0112% |
| Ingersoll Rand Inc | IR | 12,054.84 | 0.04% | 0.36% | 10.20% | 10.57% | 0.0047% |
| Iron Mountain Inc | IRM | 7,513.74 | 0.03% | 9.52% | 0.06% | 9.57% | 0.0027% |
| Intuitive Surgical Inc | ISRG | 66,452.31 | 0.25% | 0.00% | 6.77% | 6.77% | 0.0166% |
| Gartner Inc | IT | 10,819.62 | 0.04% | 0.00% | 10.00% | 10.00% | 0.0040% |
| Illinois Tool Works Inc | ITW | 55,240.72 | 0.20% | 2.47% | 5.27% | 7.80% | 0.0159% |
| Invesco Ltd | IVZ | 4,937.72 | 0.02% | 6.99% | -10.95% | -4.35% | -0.0008% |
| Jacobs Engineering Group Inc | J | 11,032.71 | 0.04% | 0.88% | 7.25% | 8.16% | 0.0033% |
| JB Hunt Transport Services Inc | JBHT | 12,691.13 | 0.05% | 0.93% | 13.05% | 14.04% | 0.0066% |
| Johnson Controls International plc | JCI | 25,395.46 | 0.09% | 3.15% | 9.10% | 12.39% | 0.0116% |
| Jack Henry & Associates Inc | JKHY | 14,099.54 | 0.05% | 0.89% | 12.10% | 13.05% | 0.0068% |
| Johnson & Johnson | JNJ | 370,503.03 | 1.37% | 2.83% | 5.44% | 8.35% | 0.1141% |
| Juniper Networks Inc | JNPR | 7,574.71 | 0.03% | 3.48% | 7.86% | 11.47% | 0.0032% |
| JPMorgan Chase & Co | JPM | 286,602.97 | 1.06% | 3.86% | 5.70% | 9.67% | 0.1022% |
| Kellogg Co | K | 22,636.78 | 0.08% | 3.50% | 2.48% | 6.02% | 0.0050% |
| KeyCorp | KEY | 11,880.44 | 0.04% | 6.08% | 17.60% | 24.22% | 0.0106% |
| Keysight Technologies Inc | KEYS | 18,849.59 | 0.07% | 0.00% | 7.83% | 7.83% | 0.0054% |
| Kraft Heinz Co/The | KHC | 38,964.26 | 0.14% | 5.02% | 1.17% | 6.21% | 0.0089% |
| Kimco Realty Corp | KIM | 5,553.63 | 0.02% | 4.41% | 4.15% | 8.65% | 0.0018% |
| KLA Corp | KLAC | 30,153.91 | 0.11% | 1.59% | 10.54% | 12.21% | 0.0136% |
| Kimberly-Clark Corp | KMB | 48,136.34 | 0.18% | 3.00% | 4.36% | 7.42% | 0.0132% |
| Kinder Morgan Inc | KMI | 34,306.76 | 0.13% | 6.94% | 4.55% | 11.65% | 0.0147% |
| CarMax Inc | KMX | 14,574.74 | 0.05% | 0.00% | 9.93% | 9.93% | 0.0053% |
| Coca-Cola Co/The | KO | 191,895.75 | 0.71% | 3.67% | 2.76% | 6.48% | 0.0459% |
| Kroger Co/The | KR | 26,332.79 | 0.10% | 1.97% | 5.46% | 7.48% | 0.0073% |
| Kohl's Corp | KSS | 3,276.19 | 0.01% | 3.38% | 1.25% | 4.65% | 0.0006% |
| Kansas City Southern | KSU | 14,185.57 | 0.05% | 1.06% | 11.65% | 12.77% | 0.0067% |
| Loews Corp | L | 9,650.25 | N/A | 0.00% | N/A | N/A | N/A |
| L Brands Inc | LB | 4,159.10 | 0.02% | 2.20% | 11.50% | 13.83% | 0.0021% |
| Leidos Holdings Inc | LDOS | 13,305.24 | 0.05% | 1.49% | 10.36% | 11.92% | 0.0058% |
| Leggett & Platt Inc | LEG | 4,649.53 | N/A | 4.59% | N/A | N/A | N/A |
| Lennar Corp | LEN | 18,655.99 | 0.07% | 0.54% | 9.74% | 10.30% | 0.0071% |
| Laboratory Corp of America Holdings | LH | 16,145.89 | 0.06% | 0.00% | 5.18% | 5.18% | 0.0031% |
| L3Harris Technologies Inc | LHX | 36,626.72 | 0.14% | 2.00% | 16.64% | 18.80% | 0.0254% |
| Linde PLC | LIN | 111,397.06 | 0.41% | 1.79% | 9.50% | 11.38% | 0.0468% |
| LKQ Corp | LKQ | 7,963.96 | 0.03% | 0.00% | 2.60% | 2.60% | 0.0008% |
| Eli Lilly and Co | LLY | 157,030.03 | 0.58% | 1.81% | 15.63% | 17.58% | 0.1018% |
| Lockheed Martin Corp | LMT | 102,336.45 | 0.38% | 2.68% | 7.48% | 10.26% | 0.0387% |
| Lincoln National Corp | LNC | 7,108.73 | 0.03% | 4.43% | 9.00% | 13.62% | 0.0036% |
| Alliant Energy Corp | LNT | 11,936.26 | 0.04% | 3.16% | 5.46% | 8.71% | 0.0038% |
| Lowe's Cos Inc | LOW | 102,015.97 | 0.38% | 1.78% | 18.20% | 20.14% | 0.0758% |
| Lam Research Corp | LRCX | 46,954.17 | 0.17% | 1.45% | 10.47% | 11.99% | 0.0208% |
| Southwest Airlines Co | LUV | 20,145.20 | 0.07% | 0.53% | -2.58% | -2.06% | -0.0015% |
| Las Vegas Sands Corp | LVS | 34,780.25 | 0.13% | 1.71% | 9.10% | 10.89% | 0.0140% |
| Lamb Weston Holdings Inc | LW | 9,336.27 | 0.03% | 1.34% | -1.07% | 0.26% | 0.0001% |
| LyondellBasell Industries NV | LYB | 21,931.17 | 0.08% | 6.43% | 5.50% | 12.11% | 0.0098% |
| Live Nation Entertainment Inc | LYV | 9,542.48 | N/A | 0.00% | N/A | N/A | N/A |
| Mastercard Inc | MA | 296,806.02 | 1.09% | 0.50% | 15.30% | 15.84% | 0.1734% |
| Mid-America Apartment Communities Inc | MAA | 13,112.65 | N/A | 3.49% | N/A | N/A | N/A |
| Marriott International Inc/MD | MAR | 27,798.46 | 0.10% | 0.65% | -1.62% | -0.97% | -0.0010% |
| Masco Corp | MAS | 13,243.16 | 0.05% | 1.07% | 9.98% | 11.10% | 0.0054% |
| McDonald's Corp | MCD | 137,163.81 | 0.51% | 2.74% | 6.95% | 9.79% | 0.0495% |
| Microchip Technology Inc | MCHP | 25,835.97 | 0.10% | 1.40% | 11.57% | 13.05% | 0.0124% |
| McKesson Corp | MCK | 24,871.77 | 0.09% | 1.13% | 8.57% | 9.75% | 0.0089% |
| Moody's Corp | MCO | 51,511.88 | 0.19% | 0.80% | 9.75% | 10.59% | 0.0201% |
| Mondelez International Inc | MDLZ | 72,986.24 | 0.27% | 2.31% | 7.75% | 10.16% | 0.0273% |
| Medtronic PLC | MDT | 122,997.11 | 0.45% | 2.46% | 7.60% | 10.16% | 0.0461% |
| MetLife Inc | MET | 33,145.14 | 0.12% | 4.99% | 4.42% | 9.52% | 0.0116% |
| MGM Resorts International | MGM | 8,286.06 | 0.03% | 0.95% | 18.70% | 19.74% | 0.0060% |
| Mohawk Industries Inc | MHK | 7,293.42 | 0.03% | 0.00% | 9.00% | 9.00% | 0.0024% |
| McCormick & Co Inc/MD | MKC | 23,885.16 | 0.09% | 1.35% | 10.03% | 11.44% | 0.0101% |
| MarketAxess Holdings Inc | MKTX | 18,989.98 | N/A | 0.48% | N/A | N/A | N/A |
| Martin Marietta Materials Inc | MLM | 12,837.03 | 0.05% | 1.04% | 10.08% | 11.17% | 0.0053% |
| Marsh & McLennan Cos Inc | MMC | 54,782.68 | 0.20% | 1.72% | 9.83% | 11.64% | 0.0235% |
| 3M Co | MMM | 89,724.88 | 0.33% | 3.79% | 7.05% | 10.97% | 0.0363% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Monster Beverage Corp | MNST | 36,501.39 | 0.13% | 0.00% | 9.60% | 9.60% | 0.0129% |
| Altria Group Inc | MO | 72,940.95 | 0.27% | 8.59% | 6.05% | 14.90% | 0.0401% |
| Mosaic Co/The | MOS | 4,741.55 | 0.02% | 1.61% | 38.35% | 40.27% | 0.0070% |
| Marathon Petroleum Corp | MPC | 24,306.75 | 0.09% | 6.17% | 4.05% | 10.35% | 0.0093% |
| Merck & Co Inc | MRK | 195,188.75 | 0.72% | 3.11% | 8.23% | 11.46% | 0.0825% |
| Marathon Oil Corp | MRO | 4,836.71 | 0.02% | 1.52% | -21.75% | -20.39% | -0.0036% |
| Morgan Stanley | MS | 76,104.20 | 0.28% | 2.92% | 1.97% | 4.91% | 0.0138% |
| MSCI Inc | MSCI | 27,905.92 | 0.10% | 0.84% | 11.45% | 12.34% | 0.0127% |
| Microsoft Corp | MSFT | 1,543,305.92 | 5.69% | 0.99% | 13.84% | 14.90% | 0.8481% |
| Motorola Solutions Inc | MSI | 23,831.54 | 0.09% | 1.81% | 13.70% | 15.63% | 0.0137% |
| M&T Bank Corp | MTB | 13,336.51 | 0.05% | 4.24% | 0.41% | 4.65% | 0.0023% |
| Mettler-Toledo International Inc | MTD | 19,258.71 | 0.07% | 0.00% | 6.02% | 6.02% | 0.0043% |
| Micron Technology Inc | MU | 57,299.82 | 0.21% | 0.00% | 5.55% | 5.55% | 0.0117% |
| Maxim Integrated Products Inc | MXIM | 16,160.16 | 0.06% | 3.17% | 8.03% | 11.33% | 0.0068% |
| Mylan NV | MYL | 8,312.51 | 0.03% | 0.00% | 0.66% | 0.66% | 0.0002% |
| Noble Energy Inc | NBL | 4,298.10 | 0.02% | 1.89% | 12.54% | 14.54% | 0.0023% |
| Norwegian Cruise Line Holdings Ltd | NCLH | 4,211.78 | 0.02% | 0.00% | -16.18% | -16.18% | -0.0025% |
| Nasdaq Inc | NDAQ | 19,601.54 | 0.07% | 1.62% | 8.78% | 10.47% | 0.0076% |
| NextEra Energy Inc | NEE | 117,551.22 | 0.43% | 2.33% | 8.45% | 10.88% | 0.0472% |
| Newmont Corp | NEM | 49,551.57 | 0.18% | 1.55% | 12.75% | 14.40% | 0.0263% |
| Netflix Inc | NFLX | 200,128.43 | 0.74% | 0.00% | 31.97% | 31.97% | 0.2359% |
| NiSource Inc | NI | 8,704.86 | 0.03% | 3.73% | 4.66% | 8.48% | 0.0027% |
| NIKE Inc | NKE | 152,471.16 | 0.56% | 1.06% | 15.23% | 16.36% | 0.0920% |
| NortonLifeLock Inc | NLOK | 11,680.44 | 0.04% | 2.52% | 7.50% | 10.12% | 0.0044% |
| Nielsen Holdings PLC | NLSN | 5,297.23 | 0.02% | 1.62% | 12.00% | 13.71% | 0.0027% |
| Northrop Grumman Corp | NOC | 51,251.09 | 0.19% | 1.83% | 18.99% | 20.99% | 0.0397% |
| National Oilwell Varco Inc | NOV | 4,755.73 | N/A | 1.30% | N/A | N/A | N/A |
| ServiceNow Inc | NOW | 77,246.46 | 0.28% | 0.00% | 29.60% | 29.60% | 0.0843% |
| NRG Energy Inc | NRG | 7,947.47 | 0.03% | 3.69% | -13.96% | -10.53% | -0.0031% |
| Norfolk Southern Corp | NSC | 44,977.37 | 0.17% | 2.16% | 5.98% | 8.21% | 0.0136% |
| NetApp Inc | NTAP | 9,841.99 | 0.04% | 4.35% | 9.73% | 14.29% | 0.0052% |
| Northern Trust Corp | NTRS | 16,506.85 | 0.06% | 3.55% | -0.70% | 2.84% | 0.0017% |
| Nucor Corp | NUE | 12,469.99 | 0.05% | 3.89% | 5.25% | 9.24% | 0.0042% |
| NVIDIA Corp | NVDA | 233,644.65 | 0.86% | 0.16% | 18.78% | 18.96% | 0.1634% |
| NVR Inc | NVR | 11,994.88 | 0.04% | 0.00% | 2.44% | 2.44% | 0.0011% |
| Newell Brands Inc | NWL | 6,734.71 | 0.02% | 5.81% | -6.27% | -0.65% | -0.0002% |
| News Corp | NWS | 6,997.42 | 0.03% | 1.62% | 3.29% | 4.93% | 0.0013% |
| Realty Income Corp | O | 20,433.26 | 0.08% | 4.68% | 4.45% | 9.23% | 0.0070% |
| Old Dominion Freight Line Inc | ODFL | 20,002.83 | 0.07% | 0.36% | 8.74% | 9.11% | 0.0067% |
| ONEOK Inc | OKE | 14,749.89 | 0.05% | 11.26% | 5.68% | 17.26% | 0.0094% |
| Omnicom Group Inc | OMC | 11,699.85 | 0.04% | 4.72% | 0.90% | 5.64% | 0.0024% |
| Oracle Corp | ORCL | 169,606.05 | 0.63% | 1.76% | 9.00% | 10.84% | 0.0678% |
| O'Reilly Automotive Inc | ORLY | 31,298.73 | 0.12% | 0.00% | 11.23% | 11.23% | 0.0130% |
| Otis Worldwide Corp | OTIS | 24,624.90 | 0.09% | 1.37% | 4.80% | 6.20% | 0.0056% |
| Occidental Petroleum Corp | OXY | 16,470.33 | 0.06% | 7.41% | 12.20% | 20.06% | 0.0122% |
| Paycom Software Inc | PAYC | 18,139.67 | 0.07% | 0.00% | 19.70% | 19.70% | 0.0132% |
| Paychex Inc | PAYX | 27,172.69 | 0.10% | 3.28% | 6.55% | 9.94% | 0.0100% |
| People's United Financial Inc | PBCT | 4,913.29 | 0.02% | 6.21% | 2.00% | 8.28% | 0.0015% |
| PACCAR Inc | PCAR | 25,877.66 | 0.10% | 1.76% | 4.53% | 6.33% | 0.0060% |
| Healthpeak Properties Inc | PEAK | 14,834.73 | 0.05% | 5.37% | 3.51% | 8.97% | 0.0049% |
| Public Service Enterprise Group Inc | PEG | 24,856.54 | 0.09% | 3.99% | 4.28% | 8.35% | 0.0077% |
| PepsiCo Inc | PEP | 183,510.81 | 0.68% | 3.04% | 4.17% | 7.26% | 0.0492% |
| Pfizer Inc | PFE | 181,643.06 | 0.67% | 4.61% | 3.50% | 8.20% | 0.0549% |
| Principal Financial Group Inc | PFG | 11,376.47 | 0.04% | 5.44% | 4.68% | 10.25% | 0.0043% |
| Procter & Gamble Co/The | PG | 296,012.59 | 1.09% | 2.52% | 7.13% | 9.75% | 0.1064% |
| Progressive Corp/The | PGR | 46,896.39 | 0.17% | 2.48% | 6.00% | 8.55% | 0.0148% |
| Parker-Hannifin Corp | PH | 23,498.41 | 0.09% | 1.93% | 9.49% | 11.51% | 0.0100% |
| PulteGroup Inc | PHM | 9,125.09 | 0.03% | 1.40% | 6.49% | 7.94% | 0.0027% |
| Packaging Corp of America | PKG | 9,465.31 | 0.03% | 3.18% | 5.37% | 8.63% | 0.0030% |
| PerkinElmer Inc | PKI | 10,925.87 | 0.04% | 0.29% | 7.31% | 7.60% | 0.0031% |
| Prologis Inc | PLD | 68,931.86 | 0.25% | 2.47% | 5.17% | 7.71% | 0.0196% |
| Philip Morris International Inc | PM | 109,092.50 | 0.40% | 6.72% | 6.09% | 13.01% | 0.0524% |
| PNC Financial Services Group Inc/The | PNC | 44,636.44 | 0.16% | 4.37% | -5.84% | -1.59% | -0.0026% |
| Pentair PLC | PNR | 6,295.90 | 0.02% | 2.00% | 4.94% | 6.99% | 0.0016% |
| Pinnacle West Capital Corp | PNW | 8,244.65 | 0.03% | 4.31% | 4.90% | 9.31% | 0.0028% |
| PPG Industries Inc | PPG | 25,020.67 | 0.09% | 1.98% | 2.20% | 4.21% | 0.0039% |
| PPL Corp | PPL | 19,851.99 | 0.07% | 6.42% | -0.37% | 6.04% | 0.0044% |
| Perrigo Co PLC | PRGO | 7,534.04 | 0.03% | 1.66% | 2.00% | 3.68% | 0.0010% |
| Prudential Financial Inc | PRU | 24,055.50 | 0.09% | 7.01% | 7.00% | 14.26% | 0.0127% |
| Public Storage | PSA | 33,540.98 | 0.12% | 4.17% | 3.68% | 7.93% | 0.0098% |
| Phillips 66 | PSX | 31,396.91 | 0.12% | 5.08% | 10.15% | 15.49% | 0.0179% |
| PVH Corp | PVH | 3,413.43 | 0.01% | 0.11% | 2.44% | 2.55% | 0.0003% |
| Quanta Services Inc | PWR | 5,418.95 | N/A | 0.51% | N/A | N/A | N/A |
| Pioneer Natural Resources Co | PXD | 16,107.14 | 0.06% | 2.20% | 15.50% | 17.87% | 0.0106% |
| PayPal Holdings Inc | PYPL | 204,574.05 | 0.75% | 0.00% | 15.59% | 15.59% | 0.1176% |
| QUALCOMM Inc | QCOM | 102,604.68 | 0.38% | 2.78% | 17.12% | 20.13% | 0.0762% |
| Qorvo Inc | QRVO | 12,647.28 | 0.05% | 0.22% | 10.19% | 10.42% | 0.0049% |
| Royal Caribbean Cruises Ltd | RCL | 10,532.08 | 0.04% | 1.55% | 16.95% | 18.63% | 0.0072% |
| Everest Re Group Ltd | RE | 8,245.32 | 0.03% | 3.02% | 10.00% | 13.17% | 0.0040% |
| Regency Centers Corp | REG | 7,791.88 | 0.03% | 5.20% | 4.27% | 9.58% | 0.0028% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Regeneron Pharmaceuticals Inc | REGN | 63,852.01 | 0.24% | 0.00% | 9.46% | 9.46% | 0.0223% |
| Regions Financial Corp | RF | 10,671.64 | 0.04% | 5.65% | -1.84% | 3.76% | 0.0015% |
| Robert Half International Inc | RHI | 6,054.44 | 0.02% | 2.55% | 0.29% | 2.84% | 0.0006% |
| Raymond James Financial Inc | RJF | 9,431.81 | 0.03% | 2.11% | 3.50% | 5.64% | 0.0020% |
| Ralph Lauren Corp | RL | 5,269.19 | 0.02% | 2.58% | 4.77% | 7.41% | 0.0014% |
| ResMed Inc | RMD | 27,776.34 | 0.10% | 0.83% | 13.80% | 14.68% | 0.0150% |
| Rockwell Automation Inc | ROK | 24,670.50 | 0.09% | 1.92% | 7.18% | 9.17% | 0.0083% |
| Rollins Inc | ROL | 13,894.06 | N/A | 1.00% | N/A | N/A | N/A |
| Roper Technologies Inc | ROP | 40,533.04 | 0.15% | 0.53% | 12.33% | 12.89% | 0.0193% |
| Ross Stores Inc | ROST | 30,338.76 | 0.11% | 0.53% | 8.75% | 9.30% | 0.0104% |
| Republic Services Inc | RSG | 26,117.52 | 0.10% | 2.01% | 5.57% | 7.64% | 0.0074% |
| Raytheon Technologies Corp | RTX | 93,432.49 | 0.34% | 2.99% | -4.34% | -1.42% | -0.0049% |
| SBA Communications Corp | SBAC | 33,255.29 | 0.12% | 0.62% | 29.90% | 30.61% | 0.0375% |
| Starbucks Corp | SBUX | 85,975.20 | 0.32% | 2.25% | 13.08% | 15.47% | 0.0491% |
| Charles Schwab Corp/The | SCHW | 43,437.31 | 0.16% | 2.14% | -5.72% | -3.64% | -0.0058% |
| Sealed Air Corp | SEE | 5,113.52 | 0.02% | 1.96% | 2.08% | 4.06% | 0.0008% |
| Sherwin-Williams Co/The | SHW | 52,468.78 | 0.19% | 0.93% | 8.92% | 9.89% | 0.0191% |
| SVB Financial Group | SIVB | 11,102.65 | 0.04% | 0.00% | 10.00% | 10.00% | 0.0041% |
| J M Smucker Co/The | SJM | 12,066.91 | 0.04% | 3.40% | 0.73% | 4.15% | 0.0018% |
| Schlumberger Ltd | SLB | 25,521.88 | 0.09% | 4.56% | 36.00% | 41.38% | 0.0390% |
| SL Green Realty Corp | SLG | 3,823.13 | 0.01% | 7.10% | 4.34% | 11.60% | 0.0016% |
| Snap-on Inc | SNA | 7,528.61 | 0.03% | 3.11% | 4.06% | 7.24% | 0.0020% |
| Synopsys Inc | SNPS | 29,403.80 | 0.11% | 0.00% | 14.23% | 14.23% | 0.0154% |
| Southern Co/The | SO | 54,805.80 | 0.20% | 4.90% | 4.30% | 9.30% | 0.0188% |
| Simon Property Group Inc | SPG | 20,907.54 | 0.08% | 9.90% | 0.60% | 10.53% | 0.0081% |
| S&P Global Inc | SPGI | 79,371.73 | 0.29% | 0.81% | 7.80% | 8.64% | 0.0253% |
| Sempra Energy | SRE | 34,295.09 | 0.13% | 3.57% | 7.49% | 11.19% | 0.0142% |
| STERIS PLC | STE | 13,034.94 | 0.05% | 1.04% | 8.20% | 9.28% | 0.0045% |
| State Street Corp | STT | 22,366.83 | 0.08% | 3.27% | 1.39% | 4.69% | 0.0039% |
| Seagate Technology PLC | STX | 12,423.21 | 0.05% | 5.32% | 4.83% | 10.27% | 0.0047% |
| Constellation Brands Inc | STZ | 33,604.14 | 0.12% | 1.75% | 6.94% | 8.74% | 0.0108% |
| Stanley Black & Decker Inc | SWK | 21,482.23 | 0.08% | 1.91% | 11.00% | 13.01% | 0.0103% |
| Skyworks Solutions Inc | SWKS | 21,331.64 | 0.08% | 1.38% | 9.48% | 10.93% | 0.0086% |
| Synchrony Financia | SYF | 12,934.97 | 0.05% | 4.00% | -4.38% | -0.46% | -0.0002% |
| Stryker Corp | SYK | 67,639.45 | 0.25% | 1.29% | 8.10% | 9.44% | 0.0236% |
| Sysco Corp | SYY | 27,746.40 | 0.10% | 3.17% | 3.80% | 7.03% | 0.0072% |
| AT&T Inc | T | 215,388.75 | 0.79% | 6.90% | 4.42% | 11.47% | 0.0911% |
| Molson Coors Beverage Co | TAP | 7,694.05 | 0.03% | 3.83% | 1.58% | 5.44% | 0.0015% |
| TransDigm Group Inc | TDG | 23,902.67 | 0.09% | 7.35% | 6.18% | 13.75% | 0.0121% |
| Teledyne Technologies Inc | TDY | 11,400.55 | 0.04% | 0.00% | 10.10% | 10.10% | 0.0042% |
| TE Connectivity Ltd | TEL | 26,899.09 | 0.10% | 2.26% | 9.28% | 11.64% | 0.0115% |
| Truist Financial Corp | TFC | 50,599.64 | 0.19% | 4.81% | 2.10% | 6.97% | 0.0130% |
| Teleflex Inc | TFX | 16,897.92 | 0.06% | 0.37% | 12.75% | 13.14% | 0.0082% |
| Target Corp | TGT | 59,966.86 | 0.22% | 2.27% | 7.83% | 10.19% | 0.0225% |
| Tiffany & Co | TIF | 14,797.01 | 0.05% | 1.70% | 6.80% | 8.56% | 0.0047% |
| TJX Cos Inc/The | TJX | 60,564.67 | 0.22% | 1.01% | 8.60% | 9.65% | 0.0216% |
| Thermo Fisher Scientific Inc | TMO | 143,106.58 | 0.53% | 0.23% | 8.30% | 8.54% | 0.0451% |
| T-Mobile US Inc | TMUS | 129,229.00 | 0.48% | 0.00% | 5.00% | 5.00% | 0.0238% |
| Tapestry Inc | TPR | 3,666.59 | 0.01% | 8.04% | 8.05% | 16.42% | 0.0022% |
| T Rowe Price Group Inc | TROW | 28,102.29 | 0.10% | 2.90% | 1.59% | 4.51% | 0.0047% |
| Travelers Cos Inc/The | TRV | 28,835.93 | 0.11% | 2.97% | 9.10% | 12.21% | 0.0130% |
| Tractor Supply Co | TSCO | 15,238.89 | 0.06% | 1.10% | 12.01% | 13.17% | 0.0074% |
| Tyson Foods Inc | TSN | 21,753.56 | 0.08% | 2.85% | 1.83% | 4.70% | 0.0038% |
| Trane Technologies PLC | TT | 21,284.72 | 0.08% | 2.46% | -0.26% | 2.20% | 0.0017% |
| Take-Two Interactive Software Inc | TTWO | 15,902.99 | 0.06% | 0.00% | 6.33% | 6.33% | 0.0037% |
| Twitter Inc | TWTR | 23,374.10 | 0.09% | 0.00% | 32.77% | 32.77% | 0.0282% |
| Texas Instruments Inc | TXN | 116,529.59 | 0.43% | 2.85% | 10.70% | 13.71% | 0.0589% |
| Textron Inc | TXT | 7,486.12 | 0.03% | 0.24% | 2.83% | 3.08% | 0.0008% |
| Tyler Technologies Inc | TYL | 13,792.51 | 0.05% | 0.00% | 12.30% | 12.30% | 0.0063% |
| Under Armour Inc | UA | 4,199.30 | 0.02% | 0.00% | 18.35% | 18.35% | 0.0028% |
| United Airlines Holdings Inc | UAL | 10,052.36 | 0.04% | 0.00% | -7.98% | -7.98% | -0.0030% |
| UDR Inc | UDR | 11,022.84 | 0.04% | 3.84% | 6.01% | 9.96% | 0.0040% |
| Universal Health Services Inc | UHS | 7,888.82 | 0.03% | 0.43% | 6.67% | 7.11% | 0.0021% |
| Ulta Beauty Inc | ULTA | 11,454.93 | 0.04% | 0.00% | 8.70% | 8.70% | 0.0037% |
| UnitedHealth Group Inc | UNH | 279,724.53 | 1.03% | 1.54% | 12.40% | 14.03% | 0.1448% |
| Unum Group | UNM | 3,374.75 | 0.01% | 7.08% | 9.00% | 16.39% | 0.0020% |
| Union Pacific Corp | UNP | 114,725.50 | 0.42% | 2.30% | 9.40% | 11.81% | 0.0500% |
| United Parcel Service Inc | UPS | 95,856.79 | 0.35% | 3.64% | 6.09% | 9.83% | 0.0348% |
| United Rentals Inc | URI | 10,738.26 | 0.04% | 0.00% | -4.40% | -4.40% | -0.0017% |
| US Bancorp | USB | 55,461.56 | 0.20% | 4.57% | 6.43% | 11.15% | 0.0228% |
| Visa Inc | V | 375,425.45 | 1.38% | 0.62% | 13.52% | 14.18% | 0.1964% |
| Varian Medical Systems Inc | VAR | 11,126.65 | 0.04% | 0.00% | 8.40% | 8.40% | 0.0034% |
| VF Corp | VFC | 23,739.75 | 0.09% | 3.23% | 8.76% | 12.13% | 0.0106% |
| ViacomCBS Inc | VIAC | 14,469.68 | 0.05% | 4.13% | 3.21% | 7.40% | 0.0040% |
| Valero Energy Corp | VLO | 23,980.83 | 0.09% | 6.67% | -0.41% | 6.25% | 0.0055% |
| Vulcan Materials Co | VMC | 15,342.52 | 0.06% | 1.14% | 14.00% | 15.22% | 0.0086% |
| Vornado Realty Trust | VNO | 7,302.53 | 0.03% | 8.44% | -4.59% | 3.66% | 0.0010% |
| Verisk Analytics Inc | VRSK | 27,616.50 | 0.10% | 0.63% | 9.18% | 9.84% | 0.0100% |
| VeriSign Inc | VRSN | 23,897.03 | 0.09% | 0.00% | 3.20% | 3.20% | 0.0028% |
| Vertex Pharmaceuticals Inc | VRTX | 75,270.62 | 0.28% | 0.00% | 24.62% | 24.62% | 0.0684% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Ventas Inc | VTR | 13,662.00 | 0.05% | 6.64% | -0.29% | 6.34% | 0.0032% |
| Verizon Communications Inc | VZ | 228,127.69 | 0.84% | 4.51% | 2.63% | 7.19% | 0.0605% |
| Westinghouse Air Brake Technologies Corp | WAB | 10,954.92 | 0.04% | 0.87% | 7.66% | 8.55% | 0.0035% |
| Waters Corp | WAT | 11,168.33 | 0.04% | 0.00% | 3.89% | 3.89% | 0.0016% |
| Walgreens Boots Alliance Inc | WBA | 37,185.36 | 0.14% | 4.38% | 1.47% | 5.89% | 0.0081% |
| Western Digital Corp | WDC | 13,231.80 | 0.05% | 3.40% | -1.20% | 2.17% | 0.0011% |
| WEC Energy Group Inc | WEC | 27,647.84 | 0.10% | 2.88% | 6.41% | 9.39% | 0.0096% |
| Welltower Inc | WELL | 21,604.55 | 0.08% | 4.93% | -0.62% | 4.29% | 0.0034% |
| Wells Fargo & Co | WFC | 104,959.94 | 0.39% | 7.34% | 9.41% | 17.09% | 0.0661% |
| Whirlpool Corp | WHR | 8,051.98 | 0.03% | 3.80% | -3.07% | 0.67% | 0.0002% |
| Willis Towers Watson PLC | WLTW | 25,354.49 | 0.09% | 1.39% | 10.00% | 11.46% | 0.0107% |
| Waste Management Inc | WM | 44,866.36 | 0.17% | 2.05% | 5.23% | 7.33% | 0.0121% |
| Williams Cos Inc/The | WMB | 23,075.01 | 0.09% | 8.42% | 7.58% | 16.31% | 0.0139% |
| Walmart Inc | WMT | 339,211.38 | 1.25% | 1.81% | 3.95% | 5.79% | 0.0725% |
| W R Berkley Corp | WRB | 10,239.12 | 0.04% | 1.82% | 10.70% | 12.62% | 0.0048% |
| Westrock Co | WRK | 7,326.55 | 0.03% | 4.54% | -0.10% | 4.44% | 0.0012% |
| West Pharmaceutical Services Inc | WST | 16,720.22 | 0.06% | 0.29% | 9.60% | 9.91% | 0.0061% |
| Western Union Co/The | WU | 8,883.76 | 0.03% | 4.08% | 5.30% | 9.49% | 0.0031% |
| Weyerhaeuser Co | WY | 16,759.79 | 0.06% | 1.57% | 54.20% | 56.20% | 0.0347% |
| Wynn Resorts Ltd | WYNN | 8,035.11 | 0.03% | 1.34% | 20.00% | 21.48% | 0.0064% |
| Xcel Energy Inc | XEL | 32,823.18 | 0.12% | 2.75% | 6.04% | 8.87% | 0.0107% |
| Xilinx Inc | XLNX | 23,927.89 | 0.09% | 1.53% | 8.20% | 9.80% | 0.0086% |
| Exxon Mobil Corp | XOM | 189,085.61 | 0.70% | 7.80% | 16.97% | 25.43% | 0.1774% |
| DENTSPLY SIRONA Inc | XRAY | 9,652.68 | 0.04% | 0.84% | -1.32% | -0.48% | -0.0002% |
| Xerox Holdings Corp | XRX | 3,254.19 | 0.01% | 6.57% | 0.50% | 7.09% | 0.0009% |
| Xylem Inc/NY | XYL | 11,687.30 | 0.04% | 1.61% | 19.97% | 21.74% | 0.0094% |
| Yum! Brands Inc | YUM | 26,158.69 | 0.10% | 2.14% | 11.46% | 13.73% | 0.0132% |
| Zimmer Biomet Holdings Inc | ZBH | 24,683.90 | 0.09% | 0.83% | 2.36% | 3.20% | 0.0029% |
| Zebra Technologies Corp | ZBRA | 13,588.79 | 0.05% | 0.00% | 12.95% | 12.95% | 0.0065% |
| Zions Bancorp NA | ZION | 5,571.31 | 0.02% | 4.01% | -5.06% | -1.16% | -0.0002% |
| Zoetis Inc | ZTS | 65,085.88 | 0.24% | 0.58% | 6.08% | 6.68% | 0.0160% |
| | Total Market Capitalization: | 27,114,041.76 | | | | | 13.21% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 13.77% | 1.47% | 12.30% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 26,698.82 | 0.10% | 0.83% | 10.50% | 11.37% | 0.0117% |
| American Airlines Group Inc | AAL | 5,514.45 | 0.02% | 0.00% | 2.00% | 2.00% | 0.0004% |
| Advance Auto Parts Inc | AAP | 9,881.44 | 0.04% | 0.70% | 11.00% | 11.74% | 0.0045% |
| Apple Inc | AAPL | 1,556,895.00 | 6.02% | 0.93% | 14.00% | 15.00% | 0.9032% |
| AbbVie Inc | ABBV | 140,490.90 | 0.54% | 4.96% | 10.50% | 15.72% | 0.0854% |
| AmerisourceBergen Corp | ABC | 20,099.31 | 0.08% | 1.70% | 7.00% | 8.76% | 0.0068% |
| ABIOMED Inc | ABMD | 10,902.01 | 0.04% | 0.00% | 10.50% | 10.50% | 0.0044% |
| Abbott Laboratories | ABT | 154,420.20 | 0.60% | 1.65% | 9.50% | 11.23% | 0.0671% |
| Accenture PLC | ACN | 128,737.40 | 0.50% | 1.62% | 7.50% | 9.18% | 0.0457% |
| Adobe Inc | ADBE | 207,206.40 | 0.80% | 0.00% | 19.50% | 19.50% | 0.1563% |
| Analog Devices Inc | ADI | 44,015.73 | 0.17% | 2.08% | 7.00% | 9.15% | 0.0156% |
| Archer-Daniels-Midland Co | ADM | 21,822.60 | 0.08% | 3.66% | 9.00% | 12.82% | 0.0108% |
| Automatic Data Processing Inc | ADP | 62,252.23 | 0.24% | 2.62% | 12.00% | 14.78% | 0.0356% |
| Autodesk Inc | ADSK | 51,170.05 | N/A | 0.00% | N/A | N/A | N/A |
| Ameren Corp | AEE | 17,149.68 | 0.07% | 2.97% | 6.00% | 9.06% | 0.0060% |
| American Electric Power Co Inc | AEP | 39,968.24 | 0.15% | 3.62% | 5.00% | 8.71% | 0.0135% |
| AES Corp/The | AES | 9,202.31 | 0.04% | 4.12% | 24.00% | 28.61% | 0.0102% |
| Aflac Inc | AFL | 25,265.49 | 0.10% | 3.24% | 7.00% | 10.35% | 0.0101% |
| American International Group Inc | AIG | 26,097.12 | 0.10% | 4.22% | 28.50% | 33.32% | 0.0336% |
| Apartment Investment and Management Co | AIV | 5,524.08 | 0.02% | 4.53% | -1.50% | 3.00% | 0.0006% |
| Assurant Inc | AIZ | 6,011.40 | 0.02% | 2.50% | 11.50% | 14.14% | 0.0033% |
| Arthur J Gallagher & Co | AJG | 17,970.29 | 0.07% | 1.90% | 13.50% | 15.53% | 0.0108% |
| Akamai Technologies Inc | AKAM | 16,375.01 | 0.06% | 0.00% | 14.00% | 14.00% | 0.0089% |
| Albemarle Corp | ALB | 7,795.31 | 0.03% | 2.10% | 4.00% | 6.14% | 0.0019% |
| Align Technology Inc | ALGN | 20,292.26 | 0.08% | 0.00% | 19.50% | 19.50% | 0.0153% |
| Alaska Air Group Inc | ALK | 4,215.70 | 0.02% | 0.00% | 2.00% | 2.00% | 0.0003% |
| Allstate Corp/The | ALL | 29,279.25 | 0.11% | 2.32% | 6.00% | 8.39% | 0.0095% |
| Allegion plc | ALLE | 9,021.69 | 0.03% | 1.31% | 9.00% | 10.37% | 0.0036% |
| Alexion Pharmaceuticals Inc | ALXN | 24,752.14 | 0.10% | 0.00% | 19.50% | 19.50% | 0.0187% |
| Applied Materials Inc | AMAT | 54,961.25 | 0.21% | 1.47% | 7.50% | 9.03% | 0.0192% |
| Amcor PLC | AMCR | 16,125.24 | N/A | 4.82% | N/A | N/A | N/A |
| Advanced Micro Devices Inc | AMD | 61,348.69 | 0.24% | 0.00% | 20.00% | 20.00% | 0.0475% |
| AMETEK Inc | AME | 19,694.44 | 0.08% | 0.84% | 12.50% | 13.39% | 0.0102% |
| Amgen Inc | AMGN | 136,715.90 | 0.53% | 2.88% | 6.50% | 9.47% | 0.0501% |
| Ameriprise Financial Inc | AMP | 17,489.01 | 0.07% | 2.91% | 11.00% | 14.07% | 0.0095% |
| American Tower Corp | AMT | 112,686.10 | 0.44% | 1.88% | 9.00% | 10.96% | 0.0478% |
| Amazon.com Inc | AMZN | 1,427,357.00 | 5.52% | 0.00% | 33.50% | 33.50% | 1.8498% |
| Arista Networks Inc | ANET | 15,830.81 | 0.06% | 0.00% | 5.50% | 5.50% | 0.0034% |
| ANSYS Inc | ANSS | 24,413.41 | 0.09% | 0.00% | 9.50% | 9.50% | 0.0090% |
| Anthem Inc | ANTM | 64,847.27 | 0.25% | 1.48% | 14.00% | 15.58% | 0.0391% |
| Aon PLC | AON | 43,338.18 | 0.17% | 0.96% | 7.50% | 8.50% | 0.0142% |
| A O Smith Corp | AOS | 7,269.03 | 0.03% | 2.13% | 6.00% | 8.19% | 0.0023% |
| Apache Corp | APA | 4,932.93 | 0.02% | 0.77% | 13.50% | 14.32% | 0.0027% |
| Air Products and Chemicals Inc | APD | 51,387.55 | 0.20% | 2.30% | 12.00% | 14.44% | 0.0287% |
| Amphenol Corp | APH | 27,995.10 | 0.11% | 1.06% | 9.00% | 10.11% | 0.0109% |
| Aptiv PLC | APTV | 19,017.20 | 0.07% | 0.00% | 9.50% | 9.50% | 0.0070% |
| Alexandria Real Estate Equities Inc | ARE | 18,148.24 | 0.07% | 2.59% | 16.50% | 19.30% | 0.0136% |
| Atmos Energy Corp | ATO | 12,103.70 | 0.05% | 2.45% | 7.00% | 9.54% | 0.0045% |
| Activision Blizzard Inc | ATVI | 58,222.68 | 0.23% | 0.54% | 8.00% | 8.56% | 0.0193% |
| AvalonBay Communities Inc | AVB | 21,317.41 | 0.08% | 4.29% | 4.50% | 8.89% | 0.0073% |
| Broadcom Inc | AVGO | 123,401.90 | 0.48% | 4.24% | 17.00% | 21.60% | 0.1031% |
| Avery Dennison Corp | AVY | 9,356.12 | 0.04% | 2.11% | 11.00% | 13.23% | 0.0048% |
| American Water Works Co Inc | AWK | 22,519.01 | 0.09% | 1.77% | 8.50% | 10.35% | 0.0090% |
| American Express Co | AXP | 76,861.40 | 0.30% | 1.80% | 7.50% | 9.37% | 0.0279% |
| AutoZone Inc | AZO | 25,687.70 | 0.10% | 0.00% | 13.00% | 13.00% | 0.0129% |
| Boeing Co/The | BA | 99,708.47 | 0.39% | 0.00% | -1.50% | -1.50% | -0.0058% |
| Bank of America Corp | BAC | 206,563.40 | 0.80% | 3.02% | 5.00% | 8.10% | 0.0647% |
| Baxter International Inc | BAX | 41,926.84 | 0.16% | 1.19% | 9.00% | 10.24% | 0.0166% |
| Best Buy Co Inc | BBY | 21,541.74 | 0.08% | 2.63% | 9.00% | 11.75% | 0.0098% |
| Becton Dickinson and Co | BDX | 63,272.17 | 0.24% | 1.38% | 9.00% | 10.44% | 0.0256% |
| Franklin Resources Inc | BEN | 10,311.83 | 0.04% | 5.28% | 6.50% | 11.95% | 0.0048% |
| Brown-Forman Corp | BF/B | 30,514.52 | 0.12% | 1.10% | 11.00% | 12.16% | 0.0144% |
| Biogen Inc | BIIB | 50,266.94 | 0.19% | 0.00% | 7.00% | 7.00% | 0.0136% |
| Bio-Rad Laboratories Inc | BIO | 12,819.96 | 0.05% | 0.00% | 12.00% | 12.00% | 0.0060% |
| Bank of New York Mellon Corp/The | BK | 32,965.05 | 0.13% | 3.33% | 3.00% | 6.38% | 0.0081% |
| Booking Holdings Inc | BKNG | 65,910.81 | 0.25% | 0.00% | 7.00% | 7.00% | 0.0178% |
| Baker Hughes Co | BKR | 9,358.74 | 0.04% | 5.03% | 45.50% | 51.67% | 0.0187% |
| BlackRock Inc | BLK | 83,081.41 | 0.32% | 2.70% | 7.00% | 9.79% | 0.0315% |
| Ball Corp | BLL | 22,481.89 | 0.09% | 0.87% | 19.00% | 19.95% | 0.0174% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Bristol-Myers Squibb Co | BMY | 130,693.00 | 0.51% | 3.12% | 12.50% | 15.82% | 0.0800% |
| Broadridge Financial Solutions Inc | BR | 14,049.15 | 0.05% | 1.76% | 9.00% | 10.84% | 0.0059% |
| Berkshire Hathaway Inc | BRK/B | - | N/A | 0.00% | N/A | N/A | N/A |
| Boston Scientific Corp | BSX | 47,366.68 | 0.18% | 0.00% | 13.50% | 13.50% | 0.0247% |
| BorgWarner Inc | BWA | 6,878.55 | 0.03% | 2.05% | 3.50% | 5.59% | 0.0015% |
| Boston Properties Inc | BXP | 13,883.12 | 0.05% | 4.37% | 4.00% | 8.46% | 0.0045% |
| Citigroup Inc | C | 107,420.10 | 0.42% | 4.02% | 3.50% | 7.59% | 0.0315% |
| Conagra Brands Inc | CAG | 16,458.30 | 0.06% | 2.58% | 5.00% | 7.64% | 0.0049% |
| Cardinal Health Inc | CAH | 15,186.92 | 0.06% | 3.73% | 12.50% | 16.46% | 0.0097% |
| Carrier Global Corp | CARR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Caterpillar Inc | CAT | 66,150.66 | 0.26% | 3.38% | 4.00% | 7.45% | 0.0191% |
| Chubb Ltd | CB | 56,949.10 | 0.22% | 2.47% | 9.50% | 12.09% | 0.0266% |
| Cboe Global Markets Inc | CBOE | 10,375.20 | 0.04% | 1.54% | 12.50% | 14.14% | 0.0057% |
| CBRE Group Inc | CBRE | 14,327.45 | 0.06% | 0.00% | 7.50% | 7.50% | 0.0042% |
| Crown Castle International Corp | CCI | 67,595.70 | 0.26% | 3.13% | 14.00% | 17.35% | 0.0454% |
| Carnival Corp | CCL | 11,920.00 | 0.05% | 0.00% | -2.50% | -2.50% | -0.0012% |
| Cadence Design Systems Inc | CDNS | 25,682.41 | 0.10% | 0.00% | 10.00% | 10.00% | 0.0099% |
| CDW Corp/DE | CDW | 15,865.03 | 0.06% | 1.36% | 11.00% | 12.43% | 0.0076% |
| Celanese Corp | CE | 9,808.28 | 0.04% | 2.99% | 7.00% | 10.09% | 0.0038% |
| Cerner Corp | CERN | 20,887.38 | 0.08% | 1.05% | 9.00% | 10.10% | 0.0082% |
| CF Industries Holdings Inc | CF | 6,030.45 | 0.02% | 4.49% | 26.50% | 31.58% | 0.0074% |
| Citizens Financial Group Inc | CFG | 10,272.22 | 0.04% | 6.48% | 1.50% | 8.03% | 0.0032% |
| Church & Dwight Co Inc | CHD | 18,738.89 | 0.07% | 1.26% | 8.00% | 9.31% | 0.0067% |
| CH Robinson Worldwide Inc | CHRW | 10,570.38 | 0.04% | 2.60% | 8.00% | 10.70% | 0.0044% |
| Charter Communications Inc | CHTR | 104,878.60 | 0.41% | 0.00% | 33.50% | 33.50% | 0.1359% |
| Cigna Corp | CI | 67,881.25 | 0.26% | 0.03% | 11.50% | 11.53% | 0.0303% |
| Cincinnati Financial Corp | CINF | 9,971.21 | 0.04% | 3.87% | 10.50% | 14.57% | 0.0056% |
| Colgate-Palmolive Co | CL | 61,695.71 | 0.24% | 2.44% | 5.00% | 7.50% | 0.0179% |
| Clorox Co/The | CLX | 26,699.45 | 0.10% | 2.09% | 4.50% | 6.64% | 0.0069% |
| Comerica Inc | CMA | 5,206.94 | 0.02% | 7.26% | 0.50% | 7.78% | 0.0016% |
| Comcast Corp | CMCSA | 175,627.30 | 0.68% | 2.39% | 9.50% | 12.00% | 0.0816% |
| CME Group Inc | CME | 59,900.67 | 0.23% | 2.03% | 2.50% | 4.56% | 0.0106% |
| Chipotle Mexican Grill Inc | CMG | 29,148.73 | 0.11% | 0.00% | 14.50% | 14.50% | 0.0164% |
| Cummins Inc | CMI | 24,574.97 | 0.10% | 3.15% | 4.00% | 7.21% | 0.0069% |
| CMS Energy Corp | CMS | 16,427.88 | 0.06% | 2.94% | 7.50% | 10.55% | 0.0067% |
| Centene Corp | CNC | 35,836.07 | 0.14% | 0.00% | 13.00% | 13.00% | 0.0180% |
| CenterPoint Energy Inc | CNP | 9,213.52 | 0.04% | 3.27% | 4.50% | 7.84% | 0.0028% |
| Capital One Financial Corp | COF | 29,804.60 | 0.12% | 2.44% | -0.50% | 1.93% | 0.0022% |
| Cabot Oil & Gas Corp | COG | 7,142.48 | 0.03% | 2.40% | 11.50% | 14.04% | 0.0039% |
| Cooper Cos Inc/The | COO | 13,816.25 | 0.05% | 0.02% | 11.00% | 11.02% | 0.0059% |
| ConocoPhillips | COP | 43,958.70 | 0.17% | 4.10% | 10.50% | 14.82% | 0.0252% |
| Costco Wholesale Corp | COST | 131,582.70 | 0.51% | 0.95% | 10.00% | 11.00% | 0.0560% |
| Coty Inc | COTY | 3,304.22 | 0.01% | 0.00% | 10.50% | 10.50% | 0.0013% |
| Campbell Soup Co | CPB | 15,781.78 | 0.06% | 2.87% | 1.50% | 4.39% | 0.0027% |
| Copart Inc | CPRT | 19,083.54 | 0.07% | 0.00% | 14.00% | 14.00% | 0.0103% |
| salesforce.com Inc | CRM | 166,809.40 | 0.65% | 0.00% | 31.50% | 31.50% | 0.2033% |
| Cisco Systems Inc | CSCO | 188,845.00 | 0.73% | 3.22% | 7.00% | 10.33% | 0.0755% |
| CSX Corp | CSX | 51,668.95 | 0.20% | 1.54% | 9.50% | 11.11% | 0.0222% |
| Cintas Corp | CTAS | 27,216.59 | 0.11% | 1.11% | 14.00% | 15.19% | 0.0160% |
| CenturyLink Inc | CTL | 10,691.71 | 0.04% | 10.27% | 2.50% | 12.90% | 0.0053% |
| Cognizant Technology Solutions Corp | CTSH | 29,105.80 | 0.11% | 1.64% | 4.00% | 5.67% | 0.0064% |
| Corteva Inc | CTVA | 19,509.98 | N/A | 2.15% | N/A | N/A | N/A |
| Citrix Systems Inc | CTXS | 17,487.05 | 0.07% | 0.99% | 9.00% | 10.03% | 0.0068% |
| CVS Health Corp | CVS | 82,449.90 | 0.32% | 3.17% | 6.00% | 9.27% | 0.0296% |
| Chevron Corp | CVX | 163,622.00 | 0.63% | 5.89% | 10.50% | 16.70% | 0.1057% |
| Concho Resources Inc | CXO | 10,151.95 | 0.04% | 1.55% | 6.00% | 7.60% | 0.0030% |
| Dominion Energy Inc | D | 69,284.63 | 0.27% | 4.59% | 10.50% | 15.33% | 0.0411% |
| Delta Air Lines Inc | DAL | 17,438.44 | 0.07% | 0.00% | 6.00% | 6.00% | 0.0040% |
| DuPont de Nemours Inc | DD | 37,819.74 | N/A | 2.41% | N/A | N/A | N/A |
| Deere & Co | DE | 47,082.15 | 0.18% | 2.02% | 5.00% | 7.07% | 0.0129% |
| Discover Financial Services | DFS | 15,563.20 | 0.06% | 3.46% | 4.50% | 8.04% | 0.0048% |
| Dollar General Corp | DG | 48,292.87 | 0.19% | 0.75% | 11.50% | 12.29% | 0.0230% |
| Quest Diagnostics Inc | DGX | 14,009.70 | 0.05% | 2.14% | 9.00% | 11.24% | 0.0061% |
| DR Horton Inc | DHI | 19,663.77 | 0.08% | 1.29% | 6.50% | 7.83% | 0.0060% |
| Danaher Corp | DHR | 119,507.60 | 0.46% | 0.42% | 15.00% | 15.45% | 0.0714% |
| Walt Disney Co/The | DIS | 199,596.70 | 0.77% | 0.00% | 5.50% | 5.50% | 0.0425% |
| Discovery Inc | DISCA | 11,012.04 | 0.04% | 0.00% | 15.00% | 15.00% | 0.0064% |
| DISH Network Corp | DISH | 18,008.58 | 0.07% | 0.00% | -1.00% | -1.00% | -0.0007% |
| Digital Realty Trust Inc | DLR | 29,250.32 | 0.11% | 3.26% | 8.50% | 11.90% | 0.0135% |
| Dollar Tree Inc | DLTR | 21,371.72 | 0.08% | 0.00% | 8.00% | 8.00% | 0.0066% |
| Dover Corp | DOV | 13,227.29 | 0.05% | 2.13% | 9.50% | 11.73% | 0.0060% |
| Dow Inc | DOW | 28,481.11 | N/A | 7.54% | N/A | N/A | N/A |
| Domino's Pizza Inc | DPZ | 14,658.74 | 0.06% | 0.83% | 13.00% | 13.88% | 0.0079% |
| Duke Realty Corp | DRE | 12,723.71 | 0.05% | 2.72% | -3.00% | -0.32% | -0.0002% |
| Darden Restaurants Inc | DRI | 8,555.48 | 0.03% | 0.00% | 4.00% | 4.00% | 0.0013% |
| DTE Energy Co | DTE | 20,276.27 | 0.08% | 4.06% | 5.00% | 9.16% | 0.0072% |
| Duke Energy Corp | DUK | 59,145.45 | 0.23% | 4.76% | 5.00% | 9.88% | 0.0226% |
| DaVita Inc | DVA | 9,400.91 | 0.04% | 0.00% | 11.50% | 11.50% | 0.0042% |
| Devon Energy Corp | DVN | 4,308.75 | 0.02% | 4.27% | 2.50% | 6.82% | 0.0011% |
| DXC Technology Co | DXC | 3,812.23 | 0.01% | 5.59% | 7.50% | 13.30% | 0.0020% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| DexCom Inc | DXCM | 36,709.33 | 0.14% | 0.00% | 51.50% | 51.50% | 0.0731% |
| Electronic Arts Inc | EA | 37,744.61 | 0.15% | 0.00% | 10.50% | 10.50% | 0.0153% |
| eBay Inc | EBAY | 34,187.77 | 0.13% | 1.33% | 7.00% | 8.38% | 0.0111% |
| Ecolab Inc | ECL | 56,877.36 | 0.22% | 0.96% | 8.50% | 9.50% | 0.0209% |
| Consolidated Edison Inc | ED | 23,891.02 | 0.09% | 4.32% | 3.00% | 7.38% | 0.0068% |
| Equifax Inc | EFX | 20,173.04 | 0.08% | 0.94% | 7.00% | 7.97% | 0.0062% |
| Edison Internationa | EIX | 19,762.19 | 0.08% | 4.78% | 12.00% | 17.07% | 0.0130% |
| Estee Lauder Cos Inc/The | EL | 67,587.38 | 0.26% | 0.00% | 11.50% | 11.50% | 0.0301% |
| Eastman Chemical Co | EMN | 9,081.11 | 0.04% | 3.95% | 5.00% | 9.05% | 0.0032% |
| Emerson Electric Co | EMR | 35,628.92 | 0.14% | 3.35% | 8.50% | 11.99% | 0.0165% |
| EOG Resources Inc | EOG | 28,490.71 | 0.11% | 3.11% | 10.50% | 13.77% | 0.0152% |
| Equinix Inc | EQIX | 59,257.84 | 0.23% | 1.59% | 16.00% | 17.72% | 0.0406% |
| Equity Residential | EQR | 21,363.65 | 0.08% | 4.19% | 1.00% | 5.21% | 0.0043% |
| Eversource Energy | ES | 27,726.99 | 0.11% | 2.79% | 6.50% | 9.38% | 0.0101% |
| Essex Property Trust Inc | ESS | 15,053.77 | 0.06% | 3.70% | 1.00% | 4.72% | 0.0027% |
| E*TRADE Financial Corp | ETFC | 10,678.05 | 0.04% | 1.16% | 5.50% | 6.69% | 0.0028% |
| Eaton Corp PLC | ETN | 33,604.00 | 0.13% | 3.48% | 4.00% | 7.55% | 0.0098% |
| Entergy Corp | ETR | 18,717.05 | 0.07% | 4.04% | 3.00% | 7.10% | 0.0051% |
| Evergy Inc | EVRG | 13,386.67 | N/A | 3.57% | N/A | N/A | N/A |
| Edwards Lifesciences Corp | EW | 41,810.06 | 0.16% | 0.00% | 13.50% | 13.50% | 0.0218% |
| Exelon Corp | EXC | 35,536.66 | 0.14% | 4.25% | 5.00% | 9.36% | 0.0129% |
| Expeditors International of Washington | EXPD | 12,235.13 | 0.05% | 1.41% | 5.50% | 6.95% | 0.0033% |
| Expedia Group Inc | EXPE | 11,452.97 | 0.04% | 0.00% | 12.00% | 12.00% | 0.0053% |
| Extra Space Storage Inc | EXR | 11,720.24 | 0.05% | 3.98% | 3.00% | 7.04% | 0.0032% |
| Ford Motor Co | F | 23,241.82 | 0.09% | 0.00% | 11.00% | 11.00% | 0.0099% |
| Diamondback Energy Inc | FANG | 6,612.49 | 0.03% | 3.58% | 4.50% | 8.16% | 0.0021% |
| Fastenal Co | FAST | 23,680.29 | 0.09% | 2.42% | 8.00% | 10.52% | 0.0096% |
| Facebook Inc | FB | 667,191.00 | 2.58% | 0.00% | 14.00% | 14.00% | 0.3614% |
| Fortune Brands Home & Security Inc | FBHS | 8,180.26 | 0.03% | 1.62% | 5.00% | 6.66% | 0.0021% |
| Freeport-McMoRan Inc | FCX | 16,732.31 | 0.06% | 0.00% | 17.00% | 17.00% | 0.0110% |
| FedEx Corp | FDX | 35,292.13 | 0.14% | 1.93% | 3.00% | 4.96% | 0.0068% |
| FirstEnergy Corp | FE | 20,467.46 | 0.08% | 4.18% | 8.50% | 12.86% | 0.0102% |
| F5 Networks Inc | FFIV | 8,185.52 | 0.03% | 0.00% | 6.50% | 6.50% | 0.0021% |
| Fidelity National Information Services | FIS | 81,496.79 | 0.32% | 1.06% | 28.50% | 29.71% | 0.0937% |
| Fiserv Inc | FISV | 65,115.14 | 0.25% | 0.00% | 14.00% | 14.00% | 0.0353% |
| Fifth Third Bancorp | FITB | 14,147.88 | 0.05% | 5.43% | 3.00% | 8.51% | 0.0047% |
| FLIR Systems Inc | FLIR | 5,076.65 | 0.02% | 1.75% | 7.50% | 9.32% | 0.0018% |
| Flowserve Corp | FLS | 3,348.61 | 0.01% | 3.10% | 12.50% | 15.79% | 0.0020% |
| FleetCor Technologies Inc | FLT | 20,640.34 | 0.08% | 0.00% | 14.00% | 14.00% | 0.0112% |
| FMC Corp | FMC | 12,508.46 | 0.05% | 1.90% | 11.00% | 13.00% | 0.0063% |
| Fox Corp | FOX | N/A | N/A | 0.00% | N/A | N/A | N/A |
| First Republic Bank/CA | FRC | 18,094.17 | 0.07% | 0.76% | 9.00% | 9.79% | 0.0069% |
| Federal Realty Investment Trust | FRT | 6,229.87 | 0.02% | 5.17% | 1.50% | 6.71% | 0.0016% |
| TechnipFMC PLC | FTI | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Fortinet Inc | FTNT | 21,842.06 | 0.08% | 0.00% | 21.00% | 21.00% | 0.0177% |
| Fortive Corp | FTV | 22,232.17 | 0.09% | 0.42% | 8.00% | 8.44% | 0.0073% |
| General Dynamics Corp | GD | 42,011.38 | 0.16% | 3.00% | 6.00% | 9.09% | 0.0148% |
| General Electric Co | GE | 57,118.51 | 0.22% | 0.61% | 8.00% | 8.63% | 0.0191% |
| Gilead Sciences Inc | GILD | 95,216.21 | 0.37% | 3.58% | 3.50% | 7.14% | 0.0263% |
| General Mills Inc | GIS | 36,523.68 | 0.14% | 3.30% | 4.00% | 7.37% | 0.0104% |
| Globe Life Inc | GL | 7,577.04 | 0.03% | 1.05% | 8.00% | 9.09% | 0.0027% |
| Corning Inc | GLW | 19,589.79 | 0.08% | 3.41% | 13.50% | 17.14% | 0.0130% |
| General Motors Co | GM | 36,177.60 | 0.14% | 0.00% | 3.50% | 3.50% | 0.0049% |
| Alphabet Inc | GOOG | 979,427.40 | 3.79% | 0.00% | 14.50% | 14.50% | 0.5494% |
| Genuine Parts Co | GPC | 12,213.56 | 0.05% | 3.73% | 6.50% | 10.35% | 0.0049% |
| Global Payments Inc | GPN | 49,907.76 | 0.19% | 0.47% | 11.50% | 12.00% | 0.0232% |
| Gap Inc/The | GPS | 3,886.66 | 0.02% | 0.00% | 2.50% | 2.50% | 0.0004% |
| Garmin Ltd | GRMN | 18,202.01 | 0.07% | 2.56% | 7.00% | 9.65% | 0.0068% |
| Goldman Sachs Group Inc/The | GS | 68,090.36 | 0.26% | 2.53% | 6.50% | 9.11% | 0.0240% |
| WW Grainger Inc | GWW | 15,761.83 | 0.06% | 1.95% | 7.00% | 9.02% | 0.0055% |
| Halliburton Co | HAL | 10,365.64 | 0.04% | 1.52% | 4.50% | 6.05% | 0.0024% |
| Hasbro Inc | HAS | 9,719.28 | 0.04% | 3.83% | 8.50% | 12.49% | 0.0047% |
| Huntington Bancshares Inc/OH | HBAN | 9,708.32 | 0.04% | 6.29% | 4.00% | 10.42% | 0.0039% |
| Hanesbrands Inc | HBI | 3,727.46 | 0.01% | 5.60% | 2.50% | 8.17% | 0.0012% |
| HCA Healthcare Inc | HCA | 31,644.00 | 0.12% | 0.00% | 10.50% | 10.50% | 0.0129% |
| Home Depot Inc/The | HD | 264,835.90 | 1.02% | 2.44% | 7.00% | 9.53% | 0.0976% |
| Hess Corp | HES | 15,038.46 | N/A | 2.04% | N/A | N/A | N/A |
| HollyFrontier Corp | HFC | 4,788.53 | 0.02% | 4.80% | 8.50% | 13.50% | 0.0025% |
| Hartford Financial Services Group Inc/Th | HIG | 13,551.38 | 0.05% | 3.43% | 11.50% | 15.13% | 0.0079% |
| Huntington Ingalls Industries Inc | HII | 6,772.41 | 0.03% | 2.46% | 7.50% | 10.05% | 0.0026% |
| Hilton Worldwide Holdings Inc | HLT | 20,284.83 | 0.08% | 0.00% | 14.00% | 14.00% | 0.0110% |
| Hologic Inc | HOLX | 13,857.65 | 0.05% | 0.00% | 9.50% | 9.50% | 0.0051% |
| Honeywell International Inc | HON | 97,100.67 | 0.38% | 2.60% | 8.00% | 10.70% | 0.0402% |
| Hewlett Packard Enterprise Co | HPE | 11,886.49 | 0.05% | 5.18% | 5.00% | 10.31% | 0.0047% |
| HP Inc | HPQ | 23,166.00 | 0.09% | 4.32% | 8.00% | 12.49% | 0.0112% |
| H&R Block Inc | HRB | 2,860.16 | 0.01% | 7.00% | 6.00% | 13.21% | 0.0015% |
| Hormel Foods Corp | HRL | 25,740.21 | 0.10% | 2.05% | 8.50% | 10.64% | 0.0106% |
| Henry Schein Inc | HSIC | 8,001.89 | 0.03% | 0.00% | 5.00% | 5.00% | 0.0015% |
| Host Hotels & Resorts Inc | HST | 7,833.13 | 0.03% | 0.00% | -9.00% | -9.00% | -0.0027% |
| Hershey Co/The | HSY | 26,640.57 | 0.10% | 2.54% | 4.50% | 7.10% | 0.0073% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Humana Inc | HUM | 49,154.19 | 0.19% | 0.69% | 10.50% | 11.23% | 0.0213% |
| Howmet Aerospace Inc | HWM | 6,375.83 | 0.02% | 0.00% | 10.00% | 10.00% | 0.0025% |
| International Business Machines Corp | IBM | 103,368.40 | 0.40% | 5.60% | 0.50% | 6.11% | 0.0244% |
| Intercontinental Exchange Inc | ICE | 49,709.09 | 0.19% | 1.32% | 9.00% | 10.38% | 0.0200% |
| IDEXX Laboratories Inc | IDXX | 27,124.62 | 0.10% | 0.00% | 10.50% | 10.50% | 0.0110% |
| IDEX Corp | IEX | 11,203.86 | 0.04% | 1.34% | 7.50% | 8.89% | 0.0039% |
| International Flavors & Fragrances Inc | IFF | 13,038.54 | 0.05% | 2.56% | 8.00% | 10.66% | 0.0054% |
| Illumina Inc | ILMN | 69,634.36 | 0.27% | 0.00% | 9.50% | 9.50% | 0.0256% |
| Incyte Corp | INCY | 22,634.60 | 0.09% | 0.00% | 66.00% | 66.00% | 0.0578% |
| IHS Markit Ltd | INFO | 28,617.09 | 0.11% | 0.95% | 11.50% | 12.50% | 0.0138% |
| Intel Corp | INTC | 250,187.00 | 0.97% | 2.23% | 7.00% | 9.31% | 0.0901% |
| Intuit Inc | INTU | 74,608.11 | 0.29% | 0.75% | 12.50% | 13.30% | 0.0384% |
| International Paper Co | IP | 13,190.22 | 0.05% | 6.11% | 6.00% | 12.29% | 0.0063% |
| Interpublic Group of Cos Inc/The | IPG | 6,405.25 | 0.02% | 6.20% | 10.00% | 16.51% | 0.0041% |
| IPG Photonics Corp | IPGP | 8,352.10 | 0.03% | 0.00% | 8.50% | 8.50% | 0.0027% |
| IQVIA Holdings Inc | IQV | 26,065.77 | 0.10% | 0.00% | 9.50% | 9.50% | 0.0096% |
| Ingersoll Rand Inc | IR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Iron Mountain Inc | IRM | 7,205.61 | 0.03% | 9.91% | 8.50% | 18.83% | 0.0052% |
| Intuitive Surgical Inc | ISRG | 64,708.33 | 0.25% | 0.00% | 11.50% | 11.50% | 0.0288% |
| Gartner Inc | IT | 10,327.74 | 0.04% | 0.00% | 12.00% | 12.00% | 0.0048% |
| Illinois Tool Works Inc | ITW | 53,396.58 | 0.21% | 2.53% | 7.00% | 9.62% | 0.0199% |
| Invesco Ltd | IVZ | 4,919.41 | 0.02% | 5.78% | 4.50% | 10.41% | 0.0020% |
| Jacobs Engineering Group Inc | J | 10,773.16 | 0.04% | 0.92% | 14.00% | 14.98% | 0.0062% |
| JB Hunt Transport Services Inc | JBHT | 12,343.16 | 0.05% | 0.93% | 6.50% | 7.46% | 0.0036% |
| Johnson Controls International plc | JCI | 24,763.17 | 0.10% | 3.12% | 5.50% | 8.71% | 0.0083% |
| Jack Henry & Associates Inc | JKHY | 13,765.51 | 0.05% | 0.96% | 10.00% | 11.01% | 0.0059% |
| Johnson & Johnson | JNJ | 368,061.10 | 1.42% | 2.89% | 10.00% | 13.03% | 0.1856% |
| Juniper Networks Inc | JNPR | 7,407.78 | 0.03% | 3.58% | 5.50% | 9.18% | 0.0026% |
| JPMorgan Chase & Co | JPM | 288,431.20 | 1.12% | 3.80% | 3.50% | 7.37% | 0.0822% |
| Kellogg Co | K | 22,232.43 | 0.09% | 3.55% | 3.00% | 6.60% | 0.0057% |
| KeyCorp | KEY | 12,181.73 | 0.05% | 5.93% | 3.00% | 9.02% | 0.0043% |
| Keysight Technologies Inc | KEYS | 18,889.72 | 0.07% | 0.00% | 17.00% | 17.00% | 0.0124% |
| Kraft Heinz Co/The | KHC | 39,262.86 | 0.15% | 4.98% | -0.50% | 4.47% | 0.0068% |
| Kimco Realty Corp | KIM | 5,531.55 | 0.02% | 0.00% | 5.00% | 5.00% | 0.0011% |
| KLA Corp | KLAC | 29,245.34 | 0.11% | 1.80% | 11.50% | 13.40% | 0.0152% |
| Kimberly-Clark Corp | KMB | 47,004.70 | 0.18% | 3.10% | 6.50% | 9.70% | 0.0176% |
| Kinder Morgan Inc | KMI | 33,491.72 | 0.13% | 7.09% | 22.00% | 29.87% | 0.0387% |
| CarMax Inc | KMX | 14,587.59 | 0.06% | 0.00% | 7.50% | 7.50% | 0.0042% |
| Coca-Cola Co/The | KO | 191,727.10 | 0.74% | 3.67% | 6.50% | 10.29% | 0.0763% |
| Kroger Co/The | KR | 25,862.16 | 0.10% | 2.13% | 5.50% | 7.69% | 0.0077% |
| Kohl's Corp | KSS | 3,261.12 | 0.01% | 0.00% | 2.00% | 2.00% | 0.0003% |
| Kansas City Southern | KSU | 13,547.24 | 0.05% | 1.12% | 11.50% | 12.68% | 0.0066% |
| Loews Corp | L | 9,335.03 | 0.04% | 0.75% | 12.00% | 12.80% | 0.0046% |
| L Brands Inc | LB | 3,853.08 | 0.01% | 0.00% | -2.50% | -2.50% | -0.0004% |
| Leidos Holdings Inc | LDOS | 13,241.50 | 0.05% | 1.46% | 10.00% | 11.53% | 0.0059% |
| Leggett & Platt Inc | LEG | 4,465.67 | 0.02% | 4.74% | 8.00% | 12.93% | 0.0022% |
| Lennar Corp | LEN | 18,434.71 | 0.07% | 0.85% | 7.00% | 7.88% | 0.0056% |
| Laboratory Corp of America Holdings | LH | 15,253.44 | 0.06% | 0.00% | 8.00% | 8.00% | 0.0047% |
| L3Harris Technologies Inc | LHX | 36,490.58 | N/A | 2.02% | N/A | N/A | N/A |
| Linde PLC | LIN | 108,221.40 | N/A | 1.97% | N/A | N/A | N/A |
| LKQ Corp | LKQ | 7,531.71 | 0.03% | 0.00% | 8.00% | 8.00% | 0.0023% |
| Eli Lilly and Co | LLY | 150,266.60 | 0.58% | 1.89% | 10.00% | 11.98% | 0.0697% |
| Lockheed Martin Corp | LMT | 100,906.10 | 0.39% | 2.78% | 8.50% | 11.40% | 0.0445% |
| Lincoln National Corp | LNC | 6,963.22 | 0.03% | 4.66% | 9.50% | 14.38% | 0.0039% |
| Alliant Energy Corp | LNT | 11,756.63 | 0.05% | 3.23% | 5.50% | 8.82% | 0.0040% |
| Lowe's Cos Inc | LOW | 99,644.91 | 0.39% | 1.67% | 10.00% | 11.75% | 0.0453% |
| Lam Research Corp | LRCX | 45,832.14 | 0.18% | 1.54% | 10.00% | 11.62% | 0.0206% |
| Southwest Airlines Co | LUV | 16,411.57 | 0.06% | 0.00% | 2.00% | 2.00% | 0.0013% |
| Las Vegas Sands Corp | LVS | 34,334.16 | 0.13% | 0.00% | 5.50% | 5.50% | 0.0073% |
| Lamb Weston Holdings Inc | LW | 9,207.76 | 0.04% | 1.51% | 9.50% | 11.08% | 0.0039% |
| LyondellBasell Industries NV | LYB | 20,235.75 | 0.08% | 6.93% | -1.50% | 5.38% | 0.0042% |
| Live Nation Entertainment Inc | LYV | 9,342.66 | N/A | 0.00% | N/A | N/A | N/A |
| Mastercard Inc | MA | 295,186.10 | 1.14% | 0.54% | 13.50% | 14.08% | 0.1607% |
| Mid-America Apartment Communities Inc | MAA | 12,582.04 | 0.05% | 3.62% | 0.50% | 4.13% | 0.0020% |
| Marriott International Inc/MD | MAR | 27,561.76 | 0.11% | 0.00% | 8.00% | 8.00% | 0.0085% |
| Masco Corp | MAS | 12,533.90 | 0.05% | 1.15% | 6.00% | 7.18% | 0.0035% |
| McDonald's Corp | MCD | 137,019.60 | 0.53% | 2.71% | 7.50% | 10.31% | 0.0547% |
| Microchip Technology Inc | MCHP | 24,797.55 | 0.10% | 1.45% | 8.00% | 9.51% | 0.0091% |
| McKesson Corp | MCK | 26,649.12 | 0.10% | 1.09% | 9.00% | 10.14% | 0.0105% |
| Moody's Corp | MCO | 49,791.13 | 0.19% | 0.84% | 8.00% | 8.87% | 0.0171% |
| Mondelez International Inc | MDLZ | 72,281.16 | 0.28% | 2.37% | 8.00% | 10.46% | 0.0293% |
| Medtronic PLC | MDT | 119,236.10 | 0.46% | 2.61% | 7.50% | 10.21% | 0.0471% |
| MetLife Inc | MET | 32,245.93 | 0.12% | 5.18% | 7.00% | 12.36% | 0.0154% |
| MGM Resorts International | MGM | 8,349.11 | 0.03% | 0.06% | 34.00% | 34.07% | 0.0110% |
| Mohawk Industries Inc | MHK | 7,067.96 | 0.03% | 0.00% | -3.00% | -3.00% | -0.0008% |
| McCormick & Co Inc/MD | MKC | 22,895.37 | 0.09% | 1.44% | 6.50% | 7.99% | 0.0071% |
| MarketAxess Holdings Inc | MKTX | 19,154.28 | 0.07% | 0.48% | 13.50% | 14.01% | 0.0104% |
| Martin Marietta Materials Inc | MLM | 12,843.68 | 0.05% | 1.07% | 9.50% | 10.62% | 0.0053% |
| Marsh & McLennan Cos Inc | MMC | 52,583.07 | 0.20% | 1.78% | 10.00% | 11.87% | 0.0241% |
| 3M Co | MMM | 87,556.34 | 0.34% | 3.86% | 4.50% | 8.45% | 0.0286% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Monster Beverage Corp | MNST | 35,861.93 | 0.14% | 0.00% | 11.50% | 11.50% | 0.0160% |
| Altria Group Inc | MO | 73,275.45 | 0.28% | 8.52% | 6.00% | 14.78% | 0.0419% |
| Mosaic Co/The | MOS | 4,536.87 | 0.02% | 1.92% | 18.50% | 20.60% | 0.0036% |
| Marathon Petroleum Corp | MPC | 23,549.50 | 0.09% | 6.40% | 3.00% | 9.50% | 0.0087% |
| Merck & Co Inc | MRK | 191,496.90 | 0.74% | 3.22% | 9.00% | 12.36% | 0.0916% |
| Marathon Oil Corp | MRO | 4,579.89 | 0.02% | 0.00% | 9.00% | 9.00% | 0.0016% |
| Morgan Stanley | MS | 73,969.72 | 0.29% | 2.98% | 5.00% | 8.05% | 0.0230% |
| MSCI Inc | MSCI | 27,486.69 | 0.11% | 0.89% | 17.00% | 17.97% | 0.0191% |
| Microsoft Corp | MSFT | 1,501,606.00 | 5.81% | 1.03% | 14.50% | 15.60% | 0.9065% |
| Motorola Solutions Inc | MSI | 23,681.00 | 0.09% | 1.87% | 8.00% | 9.94% | 0.0091% |
| M&T Bank Corp | MTB | 13,202.78 | 0.05% | 4.28% | 4.00% | 8.37% | 0.0043% |
| Mettler-Toledo International Inc | MTD | 18,744.83 | 0.07% | 0.00% | 9.50% | 9.50% | 0.0069% |
| Micron Technology Inc | MU | 53,698.48 | 0.21% | 0.00% | 13.50% | 13.50% | 0.0280% |
| Maxim Integrated Products Inc | MXIM | 16,029.70 | 0.06% | 3.21% | 3.50% | 6.77% | 0.0042% |
| Mylan NV | MYL | 8,281.44 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0032% |
| Noble Energy Inc | NBL | 4,491.10 | N/A | 0.86% | N/A | N/A | N/A |
| Norwegian Cruise Line Holdings Ltd | NCLH | 3,389.50 | 0.01% | 0.00% | -1.50% | -1.50% | -0.0002% |
| Nasdaq Inc | NDAQ | 18,944.88 | 0.07% | 1.70% | 6.00% | 7.75% | 0.0057% |
| NextEra Energy Inc | NEE | 118,285.40 | 0.46% | 2.38% | 10.00% | 12.50% | 0.0572% |
| Newmont Corp | NEM | 46,878.99 | 0.18% | 1.71% | 13.00% | 14.82% | 0.0269% |
| Netflix Inc | NFLX | 201,353.70 | 0.78% | 0.00% | 24.00% | 24.00% | 0.1870% |
| NiSource Inc | NI | 8,572.35 | 0.03% | 3.75% | 13.50% | 17.50% | 0.0058% |
| NIKE Inc | NKE | 155,624.40 | 0.60% | 0.98% | 16.00% | 17.06% | 0.1027% |
| NortonLifeLock Inc | NLOK | 12,120.36 | 0.05% | 2.53% | 4.50% | 7.09% | 0.0033% |
| Nielsen Holdings PLC | NLSN | 5,037.01 | N/A | 1.70% | N/A | N/A | N/A |
| Northrop Grumman Corp | NOC | 50,448.86 | 0.20% | 1.92% | 10.50% | 12.52% | 0.0244% |
| National Oilwell Varco Inc | NOV | 4,344.20 | N/A | 0.00% | N/A | N/A | N/A |
| ServiceNow Inc | NOW | 74,931.75 | 0.29% | 0.00% | 46.00% | 46.00% | 0.1333% |
| NRG Energy Inc | NRG | 7,999.97 | 0.03% | 3.68% | -1.50% | 2.15% | 0.0007% |
| Norfolk Southern Corp | NSC | 43,332.68 | 0.17% | 2.22% | 11.50% | 13.85% | 0.0232% |
| NetApp Inc | NTAP | 8,972.43 | 0.03% | 4.88% | 7.00% | 12.05% | 0.0042% |
| Northern Trust Corp | NTRS | 16,057.45 | 0.06% | 3.63% | 4.50% | 8.21% | 0.0051% |
| Nucor Corp | NUE | 12,247.16 | 0.05% | 3.96% | 3.00% | 7.02% | 0.0033% |
| NVIDIA Corp | NVDA | 227,193.30 | 0.88% | 0.17% | 9.50% | 9.68% | 0.0851% |
| NVR Inc | NVR | 11,708.45 | 0.05% | 0.00% | 9.00% | 9.00% | 0.0041% |
| Newell Brands Inc | NWL | 6,399.67 | 0.02% | 6.10% | 4.50% | 10.74% | 0.0027% |
| News Corp | NWS | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Realty Income Corp | O | 19,836.99 | 0.08% | 4.79% | 6.50% | 11.45% | 0.0088% |
| Old Dominion Freight Line Inc | ODFL | 19,296.01 | 0.07% | 0.37% | 6.50% | 6.88% | 0.0051% |
| ONEOK Inc | OKE | 13,368.42 | 0.05% | 12.69% | 12.50% | 25.98% | 0.0134% |
| Omnicom Group Inc | OMC | 11,239.14 | 0.04% | 4.96% | 5.50% | 10.60% | 0.0046% |
| Oracle Corp | ORCL | 172,084.80 | 0.67% | 1.76% | 9.00% | 10.84% | 0.0722% |
| O'Reilly Automotive Inc | ORLY | 30,712.45 | 0.12% | 0.00% | 10.00% | 10.00% | 0.0119% |
| Otis Worldwide Corp | OTIS | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Occidental Petroleum Corp | OXY | 16,200.25 | 0.06% | 0.22% | 14.50% | 14.74% | 0.0092% |
| Paycom Software Inc | PAYC | 18,010.91 | 0.07% | 0.00% | 23.00% | 23.00% | 0.0160% |
| Paychex Inc | PAYX | 25,632.70 | 0.10% | 3.58% | 9.00% | 12.74% | 0.0126% |
| People's United Financial Inc | PBCT | 4,728.93 | 0.02% | 6.46% | 3.00% | 9.56% | 0.0017% |
| PACCAR Inc | PCAR | 25,070.16 | 0.10% | 3.17% | 3.50% | 6.73% | 0.0065% |
| Healthpeak Properties Inc | PEAK | 13,130.72 | 0.05% | 5.69% | -15.00% | -9.74% | -0.0049% |
| Public Service Enterprise Group Inc | PEG | 24,272.64 | 0.09% | 4.11% | 5.00% | 9.21% | 0.0087% |
| PepsiCo Inc | PEP | 179,958.80 | 0.70% | 3.16% | 6.00% | 9.25% | 0.0644% |
| Pfizer Inc | PFE | 178,718.90 | 0.69% | 4.72% | 8.50% | 13.42% | 0.0928% |
| Principal Financial Group Inc | PFG | 10,810.24 | 0.04% | 5.67% | 4.50% | 10.30% | 0.0043% |
| Procter & Gamble Co/The | PG | 288,214.30 | 1.11% | 2.71% | 8.50% | 11.33% | 0.1263% |
| Progressive Corp/The | PGR | 45,237.83 | 0.18% | 0.52% | 9.50% | 10.04% | 0.0176% |
| Parker-Hannifin Corp | PH | 22,273.86 | 0.09% | 2.03% | 9.00% | 11.12% | 0.0096% |
| PulteGroup Inc | PHM | 9,074.16 | 0.04% | 1.45% | 5.50% | 6.99% | 0.0025% |
| Packaging Corp of America | PKG | 9,289.41 | 0.04% | 3.32% | 4.00% | 7.39% | 0.0027% |
| PerkinElmer Inc | PKI | 10,682.04 | 0.04% | 0.29% | 9.00% | 9.30% | 0.0038% |
| Prologis Inc | PLD | 56,735.37 | 0.22% | 2.67% | 6.00% | 8.75% | 0.0192% |
| Philip Morris International Inc | PM | 109,137.60 | 0.42% | 6.68% | 5.50% | 12.36% | 0.0522% |
| PNC Financial Services Group Inc/The | PNC | 43,833.12 | 0.17% | 4.45% | 3.00% | 7.52% | 0.0127% |
| Pentair PLC | PNR | 6,013.25 | 0.02% | 2.09% | 6.00% | 8.15% | 0.0019% |
| Pinnacle West Capital Corp | PNW | 8,056.61 | 0.03% | 4.50% | 4.50% | 9.10% | 0.0028% |
| PPG Industries Inc | PPG | 24,035.84 | 0.09% | 2.00% | 4.00% | 6.04% | 0.0056% |
| PPL Corp | PPL | 19,606.15 | 0.08% | 6.51% | 2.50% | 9.09% | 0.0069% |
| Perrigo Co PLC | PRGO | 7,353.39 | 0.03% | 1.76% | 3.50% | 5.29% | 0.0015% |
| Prudential Financial Inc | PRU | 23,512.78 | 0.09% | 7.37% | 5.50% | 13.07% | 0.0119% |
| Public Storage | PSA | 33,043.68 | 0.13% | 4.22% | 4.00% | 8.30% | 0.0106% |
| Phillips 66 | PSX | 30,562.89 | 0.12% | 5.22% | 4.00% | 9.32% | 0.0110% |
| PVH Corp | PVH | 3,380.93 | 0.01% | 0.00% | 6.50% | 6.50% | 0.0009% |
| Quanta Services Inc | PWR | 5,225.04 | 0.02% | 0.53% | 11.50% | 12.06% | 0.0024% |
| Pioneer Natural Resources Co | PXD | 15,193.78 | 0.06% | 2.39% | 14.00% | 16.56% | 0.0097% |
| PayPal Holdings Inc | PYPL | 197,064.00 | 0.76% | 0.00% | 15.50% | 15.50% | 0.1182% |
| QUALCOMM Inc | QCOM | 100,460.80 | 0.39% | 2.92% | 12.50% | 15.60% | 0.0606% |
| Qorvo Inc | QRVO | 12,559.89 | 0.05% | 0.00% | 53.00% | 53.00% | 0.0258% |
| Royal Caribbean Cruises Ltd | RCL | 10,099.91 | 0.04% | 6.47% | -0.50% | 5.95% | 0.0023% |
| Everest Re Group Ltd | RE | 8,237.32 | 0.03% | 3.01% | 9.50% | 12.65% | 0.0040% |
| Regency Centers Corp | REG | 7,433.45 | 0.03% | 5.37% | 14.50% | 20.26% | 0.0058% |

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|---|---|---|---|---|---|---|---|
| Regeneron Pharmaceuticals Inc | REGN | 67,880.05 | 0.26% | 0.00% | 6.50% | 6.50% | 0.0171% |
| Regions Financial Corp | RF | 10,800.31 | 0.04% | 5.50% | 5.00% | 10.64% | 0.0044% |
| Robert Half International Inc | RHI | 5,669.36 | 0.02% | 2.83% | 7.00% | 9.93% | 0.0022% |
| Raymond James Financial Inc | RJF | 9,357.60 | 0.04% | 2.19% | 6.50% | 8.76% | 0.0032% |
| Ralph Lauren Corp | RL | 5,122.13 | 0.02% | 3.89% | 7.00% | 11.03% | 0.0022% |
| ResMed Inc | RMD | 26,308.23 | 0.10% | 0.86% | 14.50% | 15.42% | 0.0157% |
| Rockwell Automation Inc | ROK | 23,747.39 | 0.09% | 1.99% | 7.00% | 9.06% | 0.0083% |
| Rollins Inc | ROL | 13,471.22 | 0.05% | 0.78% | 12.00% | 12.83% | 0.0067% |
| Roper Technologies Inc | ROP | 40,394.33 | 0.16% | 0.53% | 8.00% | 8.55% | 0.0134% |
| Ross Stores Inc | ROST | 30,983.01 | 0.12% | 0.00% | 9.00% | 9.00% | 0.0108% |
| Republic Services Inc | RSG | 25,250.78 | 0.10% | 2.15% | 9.00% | 11.25% | 0.0110% |
| Raytheon Technologies Corp | RTX | 53,459.46 | 0.21% | 3.11% | 3.00% | 6.16% | 0.0127% |
| SBA Communications Corp | SBAC | 32,103.34 | 0.12% | 0.68% | 31.00% | 31.79% | 0.0395% |
| Starbucks Corp | SBUX | 86,018.88 | 0.33% | 2.43% | 13.50% | 16.09% | 0.0536% |
| Charles Schwab Corp/The | SCHW | 43,511.45 | 0.17% | 2.13% | 6.50% | 8.70% | 0.0146% |
| Sealed Air Corp | SEE | 4,889.25 | 0.02% | 2.04% | 26.00% | 28.31% | 0.0054% |
| Sherwin-Williams Co/The | SHW | 51,451.82 | 0.20% | 0.95% | 8.50% | 9.49% | 0.0189% |
| SVB Financial Group | SIVB | 10,708.89 | 0.04% | 0.00% | 4.50% | 4.50% | 0.0019% |
| J M Smucker Co/The | SJM | 12,115.72 | 0.05% | 3.34% | 3.00% | 6.39% | 0.0030% |
| Schlumberger Ltd | SLB | 24,786.34 | 0.10% | 2.80% | 5.00% | 7.87% | 0.0075% |
| SL Green Realty Corp | SLG | 3,998.40 | 0.02% | 7.11% | -1.50% | 5.56% | 0.0009% |
| Snap-on Inc | SNA | 7,108.63 | 0.03% | 3.30% | 5.50% | 8.89% | 0.0024% |
| Synopsys Inc | SNPS | 28,551.79 | 0.11% | 0.00% | 11.00% | 11.00% | 0.0122% |
| Southern Co/The | SO | 55,310.97 | 0.21% | 4.93% | 3.00% | 8.00% | 0.0171% |
| Simon Property Group Inc | SPG | 19,979.72 | 0.08% | 12.90% | -1.00% | 11.84% | 0.0091% |
| S&P Global Inc | SPGI | 76,598.97 | 0.30% | 0.84% | 11.00% | 11.89% | 0.0352% |
| Sempra Energy | SRE | 35,051.68 | 0.14% | 3.55% | 10.00% | 13.73% | 0.0186% |
| STERIS PLC | STE | 12,637.25 | 0.05% | 0.99% | 9.50% | 10.54% | 0.0052% |
| State Street Corp | STT | 21,690.31 | 0.08% | 3.38% | 3.50% | 6.94% | 0.0058% |
| Seagate Technology PLC | STX | 13,190.74 | 0.05% | 5.57% | 3.00% | 8.65% | 0.0044% |
| Constellation Brands Inc | STZ | 33,099.65 | 0.13% | 1.75% | 7.50% | 9.32% | 0.0119% |
| Stanley Black & Decker Inc | SWK | 20,204.51 | 0.08% | 2.15% | 8.00% | 10.24% | 0.0080% |
| Skyworks Solutions Inc | SWKS | 21,173.68 | 0.08% | 1.39% | 10.00% | 11.46% | 0.0094% |
| Synchrony Financia | SYF | 12,883.62 | 0.05% | 3.98% | 8.00% | 12.14% | 0.0061% |
| Stryker Corp | SYK | 66,179.14 | 0.26% | 1.31% | 10.50% | 11.88% | 0.0304% |
| Sysco Corp | SYY | 27,835.03 | 0.11% | 3.28% | 9.50% | 12.94% | 0.0139% |
| AT&T Inc | T | 209,623.80 | 0.81% | 7.14% | 5.50% | 12.84% | 0.1041% |
| Molson Coors Beverage Co | TAP | 7,902.25 | 0.03% | 0.00% | 5.00% | 5.00% | 0.0015% |
| TransDigm Group Inc | TDG | 23,445.79 | 0.09% | 0.00% | 15.50% | 15.50% | 0.0141% |
| Teledyne Technologies Inc | TDY | 11,277.53 | 0.04% | 0.00% | 8.00% | 8.00% | 0.0035% |
| TE Connectivity Ltd | TEL | 25,846.95 | 0.10% | 2.46% | 4.50% | 7.02% | 0.0070% |
| Truist Financial Corp | TFC | 50,745.39 | 0.20% | 4.78% | 5.00% | 9.90% | 0.0194% |
| Teleflex Inc | TFX | 16,898.54 | 0.07% | 0.38% | 14.00% | 14.41% | 0.0094% |
| Target Corp | TGT | 59,850.42 | 0.23% | 2.27% | 9.50% | 11.88% | 0.0275% |
| Tiffany & Co | TIF | 14,730.67 | 0.06% | 1.91% | 9.50% | 11.50% | 0.0066% |
| TJX Cos Inc/The | TJX | 61,726.60 | 0.24% | 0.00% | 12.00% | 12.00% | 0.0287% |
| Thermo Fisher Scientific Inc | TMO | 137,427.20 | 0.53% | 0.25% | 10.00% | 10.26% | 0.0546% |
| T-Mobile US Inc | TMUS | 93,372.10 | 0.36% | 0.00% | 14.00% | 14.00% | 0.0506% |
| Tapestry Inc | TPR | 3,534.08 | 0.01% | 0.00% | 5.00% | 5.00% | 0.0007% |
| T Rowe Price Group Inc | TROW | 27,595.30 | 0.11% | 3.02% | 8.00% | 11.14% | 0.0119% |
| Travelers Cos Inc/The | TRV | 28,531.01 | 0.11% | 3.01% | 9.50% | 12.65% | 0.0140% |
| Tractor Supply Co | TSCO | 15,181.85 | 0.06% | 1.07% | 9.50% | 10.62% | 0.0062% |
| Tyson Foods Inc | TSN | 21,695.60 | 0.08% | 2.89% | 7.00% | 9.99% | 0.0084% |
| Trane Technologies PLC | TT | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Take-Two Interactive Software Inc | TTWO | 15,876.08 | 0.06% | 0.00% | 20.50% | 20.50% | 0.0126% |
| Twitter Inc | TWTR | 24,879.49 | 0.10% | 0.00% | 25.50% | 25.50% | 0.0245% |
| Texas Instruments Inc | TXN | 114,254.40 | 0.44% | 2.90% | 2.50% | 5.44% | 0.0240% |
| Textron Inc | TXT | 7,373.90 | 0.03% | 0.25% | 8.50% | 8.76% | 0.0025% |
| Tyler Technologies Inc | TYL | 16,296.65 | 0.06% | 0.00% | 10.50% | 10.50% | 0.0066% |
| Under Armour Inc | UA | N/A | N/A | 0.00% | N/A | N/A | N/A |
| United Airlines Holdings Inc | UAL | 8,176.79 | 0.03% | 0.00% | 3.50% | 3.50% | 0.0011% |
| UDR Inc | UDR | 10,718.53 | 0.04% | 3.96% | 11.50% | 15.69% | 0.0065% |
| Universal Health Services Inc | UHS | 7,583.89 | 0.03% | 0.00% | 11.00% | 11.00% | 0.0032% |
| Ulta Beauty Inc | ULTA | 11,262.40 | 0.04% | 0.00% | 9.00% | 9.00% | 0.0039% |
| UnitedHealth Group Inc | UNH | 273,853.40 | 1.06% | 1.73% | 12.00% | 13.83% | 0.1466% |
| Unum Group | UNM | 3,153.57 | 0.01% | 7.35% | 4.50% | 12.02% | 0.0015% |
| Union Pacific Corp | UNP | 112,335.40 | 0.43% | 2.34% | 10.50% | 12.96% | 0.0563% |
| United Parcel Service Inc | UPS | 94,235.70 | 0.36% | 3.69% | 6.00% | 9.80% | 0.0357% |
| United Rentals Inc | URI | 10,261.80 | 0.04% | 0.00% | 9.50% | 9.50% | 0.0038% |
| US Bancorp | USB | 55,529.32 | 0.21% | 4.56% | 3.50% | 8.14% | 0.0175% |
| Visa Inc | V | 373,058.10 | 1.44% | 0.66% | 14.50% | 15.21% | 0.2195% |
| Varian Medical Systems Inc | VAR | 10,467.69 | 0.04% | 0.00% | 13.50% | 13.50% | 0.0055% |
| VF Corp | VFC | 23,288.99 | 0.09% | 3.25% | 6.00% | 9.35% | 0.0084% |
| ViacomCBS Inc | VIAC | 14,501.70 | 0.06% | 4.07% | 8.00% | 12.23% | 0.0069% |
| Valero Energy Corp | VLO | 23,654.81 | 0.09% | 6.76% | 8.00% | 15.03% | 0.0138% |
| Vulcan Materials Co | VMC | 15,635.04 | 0.06% | 1.15% | 12.50% | 13.72% | 0.0083% |
| Vornado Realty Trust | VNO | 7,220.36 | 0.03% | 6.99% | -20.00% | -13.71% | -0.0038% |
| Verisk Analytics Inc | VRSK | 26,599.30 | 0.10% | 0.66% | 10.50% | 11.19% | 0.0115% |
| VeriSign Inc | VRSN | 23,456.06 | 0.09% | 0.00% | 9.50% | 9.50% | 0.0086% |
| Vertex Pharmaceuticals Inc | VRTX | 75,438.62 | 0.29% | 0.00% | 32.00% | 32.00% | 0.0934% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Ventas Inc | VTR | 12,820.97 | 0.05% | 5.23% | 4.50% | 9.85% | 0.0049% |
| Verizon Communications Inc | VZ | 223,162.10 | 0.86% | 4.62% | 4.00% | 8.71% | 0.0752% |
| Westinghouse Air Brake Technologies Corp | WAB | 11,093.21 | 0.04% | 0.82% | 10.50% | 11.36% | 0.0049% |
| Waters Corp | WAT | 10,977.87 | 0.04% | 0.00% | 10.50% | 10.50% | 0.0045% |
| Walgreens Boots Alliance Inc | WBA | 36,245.94 | 0.14% | 4.45% | 6.00% | 10.58% | 0.0148% |
| Western Digital Corp | WDC | 12,675.00 | 0.05% | 0.00% | 0.50% | 0.50% | 0.0002% |
| WEC Energy Group Inc | WEC | 27,376.60 | 0.11% | 3.02% | 6.00% | 9.11% | 0.0096% |
| Welltower Inc | WELL | 20,258.64 | 0.08% | 4.94% | 6.00% | 11.09% | 0.0087% |
| Wells Fargo & Co | WFC | 106,998.20 | N/A | 7.81% | N/A | N/A | N/A |
| Whirlpool Corp | WHR | 7,656.38 | 0.03% | 3.89% | 5.00% | 8.99% | 0.0027% |
| Willis Towers Watson PLC | WLTW | 24,569.27 | 0.10% | 1.43% | 11.50% | 13.01% | 0.0124% |
| Waste Management Inc | WM | 42,777.63 | 0.17% | 2.15% | 5.50% | 7.71% | 0.0128% |
| Williams Cos Inc/The | WMB | 22,852.92 | 0.09% | 8.49% | 12.00% | 21.00% | 0.0186% |
| Walmart Inc | WMT | 340,689.60 | 1.32% | 1.80% | 7.00% | 8.86% | 0.1168% |
| W R Berkley Corp | WRB | 10,024.11 | 0.04% | 0.86% | 10.00% | 10.90% | 0.0042% |
| Westrock Co | WRK | 6,791.04 | 0.03% | 3.05% | 5.00% | 8.13% | 0.0021% |
| West Pharmaceutical Services Inc | WST | 15,805.23 | 0.06% | 0.30% | 14.00% | 14.32% | 0.0088% |
| Western Union Co/The | WU | 8,608.36 | 0.03% | 4.30% | 5.50% | 9.92% | 0.0033% |
| Weyerhaeuser Co | WY | 16,229.98 | 0.06% | 0.00% | 17.50% | 17.50% | 0.0110% |
| Wynn Resorts Ltd | WYNN | 8,113.96 | 0.03% | 0.00% | 15.50% | 15.50% | 0.0049% |
| Xcel Energy Inc | XEL | 33,434.16 | 0.13% | 2.75% | 6.00% | 8.83% | 0.0114% |
| Xilinx Inc | XLNX | 23,114.47 | 0.09% | 1.64% | 8.00% | 9.71% | 0.0087% |
| Exxon Mobil Corp | XOM | 188,155.40 | 0.73% | 7.82% | 4.50% | 12.50% | 0.0910% |
| DENTSPLY SIRONA Inc | XRAY | 9,390.63 | 0.04% | 0.93% | 8.50% | 9.47% | 0.0034% |
| Xerox Holdings Corp | XRX | 3,292.50 | 0.01% | 6.46% | 7.50% | 14.20% | 0.0018% |
| Xylem Inc/NY | XYL | 11,234.75 | 0.04% | 1.67% | 8.50% | 10.24% | 0.0045% |
| Yum! Brands Inc | YUM | 26,054.56 | 0.10% | 2.17% | 9.50% | 11.77% | 0.0119% |
| Zimmer Biomet Holdings Inc | ZBH | 24,447.90 | 0.09% | 0.81% | 5.50% | 6.33% | 0.0060% |
| Zebra Technologies Corp | ZBRA | 13,293.03 | 0.05% | 0.00% | 11.00% | 11.00% | 0.0057% |
| Zions Bancorp NA | ZION | 5,443.16 | 0.02% | 4.09% | 4.50% | 8.68% | 0.0018% |
| Zoetis Inc | ZTS | 63,774.36 | 0.25% | 0.60% | 12.00% | 12.64% | 0.0312% |
| | | 25,849,001.89 | | | | | 13.77% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg and Value Line Beta Coefficients

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.98 | 0.85 |
| Alliant Energy Corporation | LNT | 1.00 | 0.80 |
| Ameren Corporation | AEE | 0.92 | 0.80 |
| American Electric Power Company, Inc. | AEP | 0.97 | 0.75 |
| Avangrid, Inc. | AGR | 0.78 | 0.80 |
| Avista Corporation | AVA | 0.93 | 0.60 |
| CMS Energy Corporation | CMS | 0.94 | 0.80 |
| DTE Energy Company | DTE | 1.10 | 0.90 |
| Evergy, Inc | EVRG | 1.04 | 1.05 |
| Hawaiian Electric Industries, Inc. | HE | 0.77 | 0.55 |
| NextEra Energy, Inc. | NEE | 0.91 | 0.85 |
| NorthWestern Corporation | NWE | 1.21 | 0.55 |
| OGE Energy Corp. | OGE | 1.18 | 1.05 |
| Otter Tail Corporation | OTTR | 0.98 | 0.85 |
| Pinnacle West Capital Corporation | PNW | 1.04 | 0.45 |
| PNM Resources, Inc. | PNM | 1.26 | 0.50 |
| Portland General Electric Company | POR | 1.01 | 0.55 |
| Southern Company | SO | 1.04 | 0.90 |
| WEC Energy Group, Inc. | WEC | 0.97 | 0.80 |
| Xcel Energy Inc. | XEL | 0.95 | 0.45 |
| Mean | | 1.000 | 0.743 |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line.

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

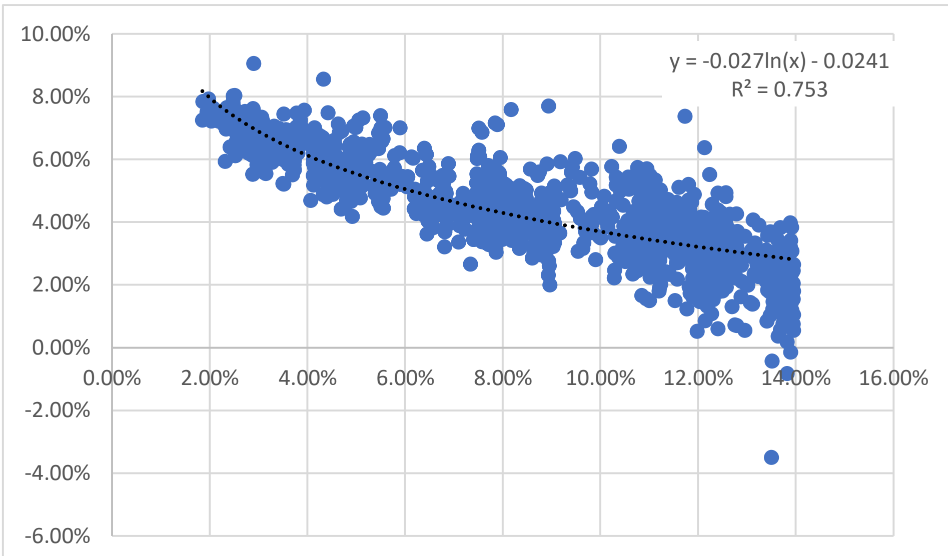
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|
| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM | |
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP BLOOMBERG BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury (30-day average) [9] | 1.47% | 1.000 | 11.73% | 12.30% | 13.21% | 13.78% | 13.21% | 13.77% |
| Near-Term Projected 30-Year Treasury [10] | 1.72% | 1.000 | 11.73% | 12.30% | 13.45% | 14.02% | 13.45% | 14.02% |
| Long-Term Projected 30-Year Treasury [11] | 3.40% | 1.000 | 11.73% | 12.30% | 15.14% | 15.70% | 15.14% | 15.70% |
| Mean | | | | | 13.93% | 14.50% | 13.93% | 14.50% |

| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM | |
|---|---|---|---|---|---|---|---|---|
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury (30-day average) [9] | 1.47% | 0.743 | 11.73% | 12.30% | 10.19% | 10.60% | 10.94% | 11.40% |
| Near-Term Projected 30-Year Treasury [10] | 1.72% | 0.743 | 11.73% | 12.30% | 10.43% | 10.85% | 11.18% | 11.64% |
| Long-Term Projected 30-Year Treasury [11] | 3.40% | 0.743 | 11.73% | 12.30% | 12.11% | 12.53% | 12.87% | 13.32% |
| Mean | | | | | 10.91% | 11.33% | 11.66% | 12.12% |

Notes:
[1] S*ee Notes [9], [10], [11]*
[2] Source: Supplemental Rebuttal Exhibit (DWD-3)
[3] Source: Supplemental Rebuttal Exhibit (DWD-2)
[4] Source: Supplemental Rebuttal Exhibit (DWD-2)
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Equals Col. [1] + (0.75 x(Col. [2] x Col. [3]) + (0.25 x Col. [3])
[8] Equals Col. [1] + (0.75 x(Col. [2] x Col. [4]) + (0.25 x Col. [4])
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 39, No. 7, July 1, 2020, at 2.
[11] Source: Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14.

Bond Yield Plus Risk Premium

| | [1] Constant | [2] Slope | [3] 30-Year Treasury Yield | [4] Risk Premium | [5] Return on Equity |
|---|---|---|---|---|---|
| | -2.41% | -2.65% | | | |
| Current 30-Year Treasury | | | 1.47% | 8.77% | 10.25% |
| Near-Term Projected 30-Year Treasury | | | 1.72% | 8.37% | 10.08% |
| Long-Term Projected 30-Year Treasury | | | 3.40% | 6.56% | 9.96% |




Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional
Near Term Projected = Blue Chip Financial Forecasts, Vol. 39, No. 7, July 1, 2020, at 2.
Long Term Projected = Blue Chip Financial Forecasts, Vol. 39, No. 6, June 1, 2020, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Global Market Intelligence
[7] Source: S&P Global Market Intelligence
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

| [6] Date of Electric Rate Case | [7] Return on Equity | [8] 30-Year Treasury Yield | [9] Risk Premium |
|---|---|---|---|
| 1/1/1980 | 14.50% | 9.36% | 5.14% |
| 1/7/1980 | 14.39% | 9.39% | 5.00% |
| 1/9/1980 | 15.00% | 9.40% | 5.60% |
| 1/14/1980 | 15.17% | 9.42% | 5.75% |
| 1/17/1980 | 13.93% | 9.44% | 4.49% |
| 1/23/1980 | 15.50% | 9.47% | 6.03% |
| 1/30/1980 | 13.86% | 9.52% | 4.34% |
| 1/31/1980 | 12.61% | 9.53% | 3.08% |
| 2/6/1980 | 13.71% | 9.58% | 4.13% |
| 2/13/1980 | 12.80% | 9.64% | 3.16% |
| 2/14/1980 | 13.00% | 9.65% | 3.35% |
| 2/19/1980 | 13.50% | 9.68% | 3.82% |
| 2/27/1980 | 13.75% | 9.78% | 3.97% |
| 2/29/1980 | 13.75% | 9.81% | 3.94% |
| 2/29/1980 | 14.00% | 9.81% | 4.19% |
| 2/29/1980 | 14.77% | 9.81% | 4.96% |
| 3/7/1980 | 12.70% | 9.90% | 2.80% |
| 3/14/1980 | 13.50% | 9.97% | 3.53% |
| 3/26/1980 | 14.16% | 10.11% | 4.05% |
| 3/27/1980 | 14.24% | 10.12% | 4.12% |
| 3/28/1980 | 14.50% | 10.14% | 4.36% |
| 4/11/1980 | 12.75% | 10.28% | 2.47% |
| 4/14/1980 | 13.85% | 10.29% | 3.56% |
| 4/16/1980 | 15.50% | 10.32% | 5.18% |
| 4/22/1980 | 13.25% | 10.36% | 2.89% |
| 4/22/1980 | 13.90% | 10.36% | 3.54% |
| 4/24/1980 | 16.80% | 10.38% | 6.42% |
| 4/29/1980 | 15.50% | 10.41% | 5.09% |
| 5/6/1980 | 13.70% | 10.45% | 3.25% |
| 5/7/1980 | 15.00% | 10.46% | 4.54% |
| 5/8/1980 | 13.75% | 10.47% | 3.28% |
| 5/9/1980 | 14.35% | 10.47% | 3.88% |
| 5/13/1980 | 13.60% | 10.49% | 3.11% |
| 5/15/1980 | 13.25% | 10.50% | 2.75% |
| 5/19/1980 | 13.75% | 10.52% | 3.23% |
| 5/27/1980 | 13.62% | 10.55% | 3.07% |
| 5/27/1980 | 14.60% | 10.55% | 4.05% |
| 5/29/1980 | 16.00% | 10.56% | 5.44% |
| 5/30/1980 | 13.80% | 10.57% | 3.23% |
| 6/2/1980 | 15.63% | 10.58% | 5.05% |
| 6/9/1980 | 15.90% | 10.61% | 5.29% |
| 6/10/1980 | 13.78% | 10.61% | 3.17% |
| 6/12/1980 | 14.25% | 10.62% | 3.63% |
| 6/19/1980 | 13.40% | 10.63% | 2.77% |
| 6/30/1980 | 13.00% | 10.65% | 2.35% |
| 6/30/1980 | 13.40% | 10.65% | 2.75% |
| 7/9/1980 | 14.75% | 10.68% | 4.07% |
| 7/10/1980 | 15.00% | 10.69% | 4.31% |
| 7/15/1980 | 15.80% | 10.70% | 5.10% |
| 7/18/1980 | 13.80% | 10.72% | 3.08% |
| 7/22/1980 | 14.10% | 10.73% | 3.37% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 7/24/1980 | 15.00% | 10.73% | 4.27% |
| 7/25/1980 | 13.48% | 10.74% | 2.74% |
| 7/31/1980 | 14.58% | 10.76% | 3.82% |
| 8/8/1980 | 13.50% | 10.78% | 2.72% |
| 8/8/1980 | 14.00% | 10.78% | 3.22% |
| 8/8/1980 | 15.45% | 10.78% | 4.67% |
| 8/11/1980 | 14.85% | 10.78% | 4.07% |
| 8/14/1980 | 14.00% | 10.79% | 3.21% |
| 8/14/1980 | 16.25% | 10.79% | 5.46% |
| 8/25/1980 | 13.75% | 10.82% | 2.93% |
| 8/27/1980 | 13.80% | 10.83% | 2.97% |
| 8/29/1980 | 12.50% | 10.84% | 1.66% |
| 9/15/1980 | 13.50% | 10.88% | 2.62% |
| 9/15/1980 | 13.93% | 10.88% | 3.05% |
| 9/15/1980 | 15.80% | 10.88% | 4.92% |
| 9/24/1980 | 12.50% | 10.93% | 1.57% |
| 9/24/1980 | 15.00% | 10.93% | 4.07% |
| 9/26/1980 | 13.75% | 10.95% | 2.80% |
| 9/30/1980 | 14.10% | 10.96% | 3.14% |
| 9/30/1980 | 14.20% | 10.96% | 3.24% |
| 10/1/1980 | 13.90% | 10.97% | 2.93% |
| 10/3/1980 | 15.50% | 10.99% | 4.51% |
| 10/7/1980 | 12.50% | 11.00% | 1.50% |
| 10/9/1980 | 13.25% | 11.01% | 2.24% |
| 10/9/1980 | 14.50% | 11.01% | 3.49% |
| 10/9/1980 | 14.50% | 11.01% | 3.49% |
| 10/16/1980 | 16.10% | 11.03% | 5.07% |
| 10/17/1980 | 14.50% | 11.03% | 3.47% |
| 10/31/1980 | 13.75% | 11.11% | 2.64% |
| 10/31/1980 | 14.25% | 11.11% | 3.14% |
| 11/4/1980 | 15.00% | 11.12% | 3.88% |
| 11/5/1980 | 13.75% | 11.13% | 2.62% |
| 11/5/1980 | 14.00% | 11.13% | 2.87% |
| 11/8/1980 | 13.75% | 11.15% | 2.60% |
| 11/10/1980 | 14.85% | 11.15% | 3.70% |
| 11/17/1980 | 14.00% | 11.18% | 2.82% |
| 11/18/1980 | 14.00% | 11.19% | 2.81% |
| 11/19/1980 | 13.00% | 11.19% | 1.81% |
| 11/24/1980 | 14.00% | 11.20% | 2.80% |
| 11/26/1980 | 14.00% | 11.21% | 2.79% |
| 12/8/1980 | 14.15% | 11.22% | 2.93% |
| 12/8/1980 | 15.10% | 11.22% | 3.88% |
| 12/9/1980 | 15.35% | 11.22% | 4.13% |
| 12/12/1980 | 15.45% | 11.22% | 4.23% |
| 12/17/1980 | 13.25% | 11.23% | 2.02% |
| 12/18/1980 | 15.80% | 11.23% | 4.57% |
| 12/19/1980 | 14.50% | 11.23% | 3.27% |
| 12/19/1980 | 14.64% | 11.23% | 3.41% |
| 12/22/1980 | 13.45% | 11.22% | 2.23% |
| 12/22/1980 | 15.00% | 11.22% | 3.78% |
| 12/30/1980 | 14.50% | 11.21% | 3.29% |
| 12/30/1980 | 14.95% | 11.21% | 3.74% |
| 12/31/1980 | 13.39% | 11.21% | 2.18% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 1/2/1981 | 15.25% | 11.21% | 4.04% |
| 1/7/1981 | 14.30% | 11.21% | 3.09% |
| 1/19/1981 | 15.25% | 11.19% | 4.06% |
| 1/23/1981 | 13.10% | 11.20% | 1.90% |
| 1/23/1981 | 14.40% | 11.20% | 3.20% |
| 1/26/1981 | 15.25% | 11.20% | 4.05% |
| 1/27/1981 | 15.00% | 11.20% | 3.80% |
| 1/31/1981 | 13.47% | 11.21% | 2.26% |
| 2/3/1981 | 15.25% | 11.23% | 4.02% |
| 2/5/1981 | 15.75% | 11.25% | 4.50% |
| 2/11/1981 | 15.60% | 11.28% | 4.32% |
| 2/20/1981 | 15.25% | 11.34% | 3.91% |
| 3/11/1981 | 15.40% | 11.50% | 3.90% |
| 3/12/1981 | 14.51% | 11.51% | 3.00% |
| 3/12/1981 | 16.00% | 11.51% | 4.49% |
| 3/13/1981 | 13.02% | 11.52% | 1.50% |
| 3/18/1981 | 16.19% | 11.55% | 4.64% |
| 3/19/1981 | 13.75% | 11.56% | 2.19% |
| 3/23/1981 | 14.30% | 11.58% | 2.72% |
| 3/25/1981 | 15.30% | 11.61% | 3.69% |
| 4/1/1981 | 14.53% | 11.69% | 2.84% |
| 4/3/1981 | 19.10% | 11.72% | 7.38% |
| 4/9/1981 | 15.00% | 11.79% | 3.21% |
| 4/9/1981 | 15.30% | 11.79% | 3.51% |
| 4/9/1981 | 16.50% | 11.79% | 4.71% |
| 4/9/1981 | 17.00% | 11.79% | 5.21% |
| 4/10/1981 | 13.75% | 11.81% | 1.94% |
| 4/13/1981 | 13.57% | 11.83% | 1.74% |
| 4/15/1981 | 15.30% | 11.86% | 3.44% |
| 4/16/1981 | 13.50% | 11.88% | 1.62% |
| 4/17/1981 | 14.10% | 11.88% | 2.22% |
| 4/21/1981 | 14.00% | 11.91% | 2.09% |
| 4/21/1981 | 16.80% | 11.91% | 4.89% |
| 4/24/1981 | 16.00% | 11.96% | 4.04% |
| 4/27/1981 | 12.50% | 11.98% | 0.52% |
| 4/27/1981 | 13.61% | 11.98% | 1.63% |
| 4/29/1981 | 13.65% | 12.01% | 1.64% |
| 4/30/1981 | 13.50% | 12.02% | 1.48% |
| 5/4/1981 | 16.22% | 12.06% | 4.16% |
| 5/5/1981 | 14.40% | 12.08% | 2.32% |
| 5/7/1981 | 16.25% | 12.12% | 4.13% |
| 5/7/1981 | 16.27% | 12.12% | 4.15% |
| 5/8/1981 | 13.00% | 12.14% | 0.86% |
| 5/8/1981 | 16.00% | 12.14% | 3.86% |
| 5/12/1981 | 13.50% | 12.17% | 1.33% |
| 5/15/1981 | 15.75% | 12.23% | 3.52% |
| 5/18/1981 | 14.88% | 12.24% | 2.64% |
| 5/20/1981 | 16.00% | 12.27% | 3.73% |
| 5/21/1981 | 14.00% | 12.28% | 1.72% |
| 5/26/1981 | 14.90% | 12.31% | 2.59% |
| 5/27/1981 | 15.00% | 12.32% | 2.68% |
| 5/29/1981 | 15.50% | 12.34% | 3.16% |
| 6/1/1981 | 16.50% | 12.35% | 4.15% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/3/1981 | 14.67% | 12.38% | 2.29% |
| 6/5/1981 | 13.00% | 12.40% | 0.60% |
| 6/10/1981 | 16.75% | 12.42% | 4.33% |
| 6/17/1981 | 14.40% | 12.46% | 1.94% |
| 6/18/1981 | 16.33% | 12.47% | 3.86% |
| 6/25/1981 | 14.75% | 12.52% | 2.23% |
| 6/26/1981 | 16.00% | 12.53% | 3.47% |
| 6/30/1981 | 15.25% | 12.55% | 2.70% |
| 7/1/1981 | 15.50% | 12.56% | 2.94% |
| 7/1/1981 | 17.50% | 12.56% | 4.94% |
| 7/10/1981 | 16.00% | 12.62% | 3.38% |
| 7/14/1981 | 16.90% | 12.64% | 4.26% |
| 7/15/1981 | 16.00% | 12.65% | 3.35% |
| 7/17/1981 | 15.00% | 12.67% | 2.33% |
| 7/20/1981 | 15.00% | 12.68% | 2.32% |
| 7/21/1981 | 14.00% | 12.69% | 1.31% |
| 7/28/1981 | 13.48% | 12.75% | 0.73% |
| 7/31/1981 | 13.50% | 12.79% | 0.71% |
| 7/31/1981 | 15.00% | 12.79% | 2.21% |
| 7/31/1981 | 16.00% | 12.79% | 3.21% |
| 8/5/1981 | 15.71% | 12.83% | 2.88% |
| 8/10/1981 | 14.50% | 12.87% | 1.63% |
| 8/11/1981 | 15.00% | 12.88% | 2.12% |
| 8/20/1981 | 13.50% | 12.95% | 0.55% |
| 8/20/1981 | 16.50% | 12.95% | 3.55% |
| 8/24/1981 | 15.00% | 12.97% | 2.03% |
| 8/28/1981 | 15.00% | 13.01% | 1.99% |
| 9/3/1981 | 14.50% | 13.06% | 1.44% |
| 9/10/1981 | 14.50% | 13.11% | 1.39% |
| 9/11/1981 | 16.00% | 13.12% | 2.88% |
| 9/16/1981 | 16.00% | 13.15% | 2.85% |
| 9/17/1981 | 16.50% | 13.16% | 3.34% |
| 9/23/1981 | 15.85% | 13.20% | 2.65% |
| 9/28/1981 | 15.50% | 13.23% | 2.27% |
| 10/9/1981 | 15.75% | 13.34% | 2.41% |
| 10/15/1981 | 16.25% | 13.37% | 2.88% |
| 10/16/1981 | 15.50% | 13.39% | 2.11% |
| 10/16/1981 | 16.50% | 13.39% | 3.11% |
| 10/19/1981 | 14.25% | 13.40% | 0.85% |
| 10/20/1981 | 15.25% | 13.41% | 1.84% |
| 10/20/1981 | 17.00% | 13.41% | 3.59% |
| 10/23/1981 | 16.00% | 13.46% | 2.54% |
| 10/27/1981 | 10.00% | 13.49% | -3.49% |
| 10/29/1981 | 14.75% | 13.52% | 1.23% |
| 10/29/1981 | 16.50% | 13.52% | 2.98% |
| 11/3/1981 | 15.17% | 13.54% | 1.63% |
| 11/5/1981 | 16.60% | 13.56% | 3.04% |
| 11/6/1981 | 15.17% | 13.57% | 1.60% |
| 11/24/1981 | 15.50% | 13.61% | 1.89% |
| 11/25/1981 | 15.25% | 13.61% | 1.64% |
| 11/25/1981 | 15.35% | 13.61% | 1.74% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/1/1981 | 15.70% | 13.61% | 2.09% |
| 12/1/1981 | 16.00% | 13.61% | 2.39% |
| 12/1/1981 | 16.49% | 13.61% | 2.88% |
| 12/1/1981 | 16.50% | 13.61% | 2.89% |
| 12/4/1981 | 16.00% | 13.61% | 2.39% |
| 12/11/1981 | 16.25% | 13.63% | 2.62% |
| 12/14/1981 | 14.00% | 13.63% | 0.37% |
| 12/15/1981 | 15.81% | 13.63% | 2.18% |
| 12/15/1981 | 16.00% | 13.63% | 2.37% |
| 12/16/1981 | 15.25% | 13.63% | 1.62% |
| 12/17/1981 | 16.50% | 13.64% | 2.86% |
| 12/18/1981 | 15.45% | 13.64% | 1.81% |
| 12/30/1981 | 14.25% | 13.67% | 0.58% |
| 12/30/1981 | 16.00% | 13.67% | 2.33% |
| 12/30/1981 | 16.25% | 13.67% | 2.58% |
| 12/31/1981 | 16.15% | 13.68% | 2.47% |
| 1/4/1982 | 15.50% | 13.68% | 1.82% |
| 1/11/1982 | 14.50% | 13.73% | 0.77% |
| 1/11/1982 | 17.00% | 13.73% | 3.27% |
| 1/13/1982 | 14.75% | 13.74% | 1.01% |
| 1/14/1982 | 15.75% | 13.75% | 2.00% |
| 1/15/1982 | 15.00% | 13.76% | 1.24% |
| 1/15/1982 | 16.50% | 13.76% | 2.74% |
| 1/22/1982 | 16.25% | 13.80% | 2.45% |
| 1/27/1982 | 16.84% | 13.81% | 3.03% |
| 1/28/1982 | 13.00% | 13.82% | -0.82% |
| 1/29/1982 | 15.50% | 13.82% | 1.68% |
| 2/1/1982 | 15.85% | 13.83% | 2.02% |
| 2/3/1982 | 16.44% | 13.84% | 2.60% |
| 2/8/1982 | 15.50% | 13.86% | 1.64% |
| 2/11/1982 | 16.00% | 13.88% | 2.12% |
| 2/11/1982 | 16.20% | 13.88% | 2.32% |
| 2/17/1982 | 15.00% | 13.89% | 1.11% |
| 2/19/1982 | 15.17% | 13.89% | 1.28% |
| 2/26/1982 | 15.25% | 13.89% | 1.36% |
| 3/1/1982 | 15.03% | 13.89% | 1.14% |
| 3/1/1982 | 16.00% | 13.89% | 2.11% |
| 3/3/1982 | 15.00% | 13.88% | 1.12% |
| 3/8/1982 | 17.10% | 13.88% | 3.22% |
| 3/12/1982 | 16.25% | 13.88% | 2.37% |
| 3/17/1982 | 17.30% | 13.88% | 3.42% |
| 3/22/1982 | 15.10% | 13.89% | 1.21% |
| 3/27/1982 | 15.40% | 13.90% | 1.50% |
| 3/30/1982 | 15.50% | 13.91% | 1.59% |
| 3/31/1982 | 17.00% | 13.91% | 3.09% |
| 4/1/1982 | 14.70% | 13.92% | 0.78% |
| 4/1/1982 | 16.50% | 13.92% | 2.58% |
| 4/2/1982 | 15.50% | 13.92% | 1.58% |
| 4/5/1982 | 15.50% | 13.93% | 1.57% |
| 4/8/1982 | 16.40% | 13.94% | 2.46% |
| 4/13/1982 | 14.50% | 13.94% | 0.56% |
| 4/23/1982 | 15.75% | 13.94% | 1.81% |
| 4/27/1982 | 15.00% | 13.94% | 1.06% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 4/28/1982 | 15.75% | 13.94% | 1.81% |
| 4/30/1982 | 14.70% | 13.94% | 0.76% |
| 4/30/1982 | 15.50% | 13.94% | 1.56% |
| 5/3/1982 | 16.60% | 13.94% | 2.66% |
| 5/4/1982 | 16.00% | 13.94% | 2.06% |
| 5/14/1982 | 15.50% | 13.92% | 1.58% |
| 5/18/1982 | 15.42% | 13.92% | 1.50% |
| 5/19/1982 | 14.69% | 13.92% | 0.77% |
| 5/20/1982 | 15.00% | 13.91% | 1.09% |
| 5/20/1982 | 15.10% | 13.91% | 1.19% |
| 5/20/1982 | 15.50% | 13.91% | 1.59% |
| 5/20/1982 | 16.30% | 13.91% | 2.39% |
| 5/21/1982 | 17.75% | 13.91% | 3.84% |
| 5/27/1982 | 15.00% | 13.89% | 1.11% |
| 5/28/1982 | 15.50% | 13.89% | 1.61% |
| 5/28/1982 | 17.00% | 13.89% | 3.11% |
| 6/1/1982 | 13.75% | 13.89% | -0.14% |
| 6/1/1982 | 16.60% | 13.89% | 2.71% |
| 6/9/1982 | 17.86% | 13.88% | 3.98% |
| 6/14/1982 | 15.75% | 13.88% | 1.87% |
| 6/15/1982 | 14.85% | 13.87% | 0.98% |
| 6/18/1982 | 15.50% | 13.86% | 1.64% |
| 6/21/1982 | 14.90% | 13.86% | 1.04% |
| 6/23/1982 | 16.00% | 13.86% | 2.14% |
| 6/23/1982 | 16.17% | 13.86% | 2.31% |
| 6/24/1982 | 14.85% | 13.86% | 0.99% |
| 6/25/1982 | 14.70% | 13.85% | 0.85% |
| 7/1/1982 | 16.00% | 13.84% | 2.16% |
| 7/2/1982 | 15.62% | 13.83% | 1.79% |
| 7/2/1982 | 17.00% | 13.83% | 3.17% |
| 7/13/1982 | 14.00% | 13.82% | 0.18% |
| 7/13/1982 | 16.80% | 13.82% | 2.98% |
| 7/14/1982 | 15.76% | 13.81% | 1.95% |
| 7/14/1982 | 16.02% | 13.81% | 2.21% |
| 7/19/1982 | 16.50% | 13.79% | 2.71% |
| 7/22/1982 | 14.50% | 13.76% | 0.74% |
| 7/22/1982 | 17.00% | 13.76% | 3.24% |
| 7/27/1982 | 16.75% | 13.74% | 3.01% |
| 7/29/1982 | 16.50% | 13.73% | 2.77% |
| 8/11/1982 | 17.50% | 13.68% | 3.82% |
| 8/18/1982 | 17.07% | 13.62% | 3.45% |
| 8/20/1982 | 15.73% | 13.60% | 2.13% |
| 8/25/1982 | 16.00% | 13.57% | 2.43% |
| 8/26/1982 | 15.50% | 13.56% | 1.94% |
| 8/30/1982 | 15.00% | 13.55% | 1.45% |
| 9/3/1982 | 16.20% | 13.53% | 2.67% |
| 9/8/1982 | 15.00% | 13.52% | 1.48% |
| 9/15/1982 | 13.08% | 13.51% | -0.43% |
| 9/15/1982 | 16.25% | 13.51% | 2.74% |
| 9/16/1982 | 16.00% | 13.50% | 2.50% |
| 9/17/1982 | 15.25% | 13.50% | 1.75% |
| 9/23/1982 | 17.17% | 13.47% | 3.70% |
| 9/24/1982 | 14.50% | 13.47% | 1.03% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/27/1982 | 15.25% | 13.46% | 1.79% |
| 10/1/1982 | 15.50% | 13.42% | 2.08% |
| 10/15/1982 | 15.90% | 13.32% | 2.58% |
| 10/22/1982 | 15.75% | 13.24% | 2.51% |
| 10/22/1982 | 17.15% | 13.24% | 3.91% |
| 10/29/1982 | 15.54% | 13.16% | 2.38% |
| 11/1/1982 | 15.50% | 13.14% | 2.36% |
| 11/3/1982 | 17.20% | 13.12% | 4.08% |
| 11/4/1982 | 16.25% | 13.10% | 3.15% |
| 11/5/1982 | 16.20% | 13.09% | 3.11% |
| 11/9/1982 | 16.00% | 13.05% | 2.95% |
| 11/23/1982 | 15.50% | 12.88% | 2.62% |
| 11/23/1982 | 15.85% | 12.88% | 2.97% |
| 11/30/1982 | 16.50% | 12.80% | 3.70% |
| 12/1/1982 | 17.04% | 12.78% | 4.26% |
| 12/6/1982 | 15.00% | 12.72% | 2.28% |
| 12/6/1982 | 16.35% | 12.72% | 3.63% |
| 12/10/1982 | 15.50% | 12.66% | 2.84% |
| 12/13/1982 | 16.00% | 12.64% | 3.36% |
| 12/14/1982 | 15.30% | 12.62% | 2.68% |
| 12/14/1982 | 16.40% | 12.62% | 3.78% |
| 12/20/1982 | 16.00% | 12.57% | 3.43% |
| 12/21/1982 | 14.75% | 12.55% | 2.20% |
| 12/21/1982 | 15.85% | 12.55% | 3.30% |
| 12/22/1982 | 16.25% | 12.54% | 3.71% |
| 12/22/1982 | 16.58% | 12.54% | 4.04% |
| 12/22/1982 | 16.75% | 12.54% | 4.21% |
| 12/29/1982 | 14.90% | 12.48% | 2.42% |
| 12/29/1982 | 16.25% | 12.48% | 3.77% |
| 12/30/1982 | 16.00% | 12.46% | 3.54% |
| 12/30/1982 | 16.35% | 12.46% | 3.89% |
| 12/30/1982 | 16.77% | 12.46% | 4.31% |
| 1/5/1983 | 17.33% | 12.40% | 4.93% |
| 1/11/1983 | 15.90% | 12.34% | 3.56% |
| 1/12/1983 | 14.63% | 12.32% | 2.31% |
| 1/12/1983 | 15.50% | 12.32% | 3.18% |
| 1/20/1983 | 17.75% | 12.23% | 5.52% |
| 1/21/1983 | 15.00% | 12.21% | 2.79% |
| 1/24/1983 | 14.50% | 12.20% | 2.30% |
| 1/24/1983 | 15.50% | 12.20% | 3.30% |
| 1/25/1983 | 15.85% | 12.19% | 3.66% |
| 1/27/1983 | 16.14% | 12.16% | 3.98% |
| 2/1/1983 | 18.50% | 12.13% | 6.37% |
| 2/4/1983 | 14.00% | 12.09% | 1.91% |
| 2/10/1983 | 15.00% | 12.05% | 2.95% |
| 2/21/1983 | 15.50% | 11.98% | 3.52% |
| 2/22/1983 | 15.50% | 11.96% | 3.54% |
| 2/23/1983 | 15.10% | 11.95% | 3.15% |
| 2/23/1983 | 16.00% | 11.95% | 4.05% |
| 3/2/1983 | 15.25% | 11.89% | 3.36% |
| 3/9/1983 | 15.20% | 11.82% | 3.38% |
| 3/15/1983 | 13.00% | 11.76% | 1.24% |
| 3/18/1983 | 15.25% | 11.72% | 3.53% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/23/1983 | 15.40% | 11.68% | 3.72% |
| 3/24/1983 | 15.00% | 11.66% | 3.34% |
| 3/29/1983 | 15.50% | 11.62% | 3.88% |
| 3/30/1983 | 16.71% | 11.60% | 5.11% |
| 3/31/1983 | 15.00% | 11.58% | 3.42% |
| 4/4/1983 | 15.20% | 11.57% | 3.63% |
| 4/8/1983 | 15.50% | 11.49% | 4.01% |
| 4/11/1983 | 14.81% | 11.48% | 3.33% |
| 4/19/1983 | 14.50% | 11.36% | 3.14% |
| 4/20/1983 | 16.00% | 11.35% | 4.65% |
| 4/29/1983 | 16.00% | 11.23% | 4.77% |
| 5/1/1983 | 14.50% | 11.23% | 3.27% |
| 5/9/1983 | 15.50% | 11.14% | 4.36% |
| 5/11/1983 | 16.46% | 11.11% | 5.35% |
| 5/12/1983 | 14.14% | 11.10% | 3.04% |
| 5/18/1983 | 15.00% | 11.04% | 3.96% |
| 5/23/1983 | 14.90% | 11.00% | 3.90% |
| 5/23/1983 | 15.50% | 11.00% | 4.50% |
| 5/25/1983 | 15.50% | 10.97% | 4.53% |
| 5/27/1983 | 15.00% | 10.95% | 4.05% |
| 5/31/1983 | 14.00% | 10.94% | 3.06% |
| 5/31/1983 | 15.50% | 10.94% | 4.56% |
| 6/2/1983 | 14.50% | 10.92% | 3.58% |
| 6/17/1983 | 15.03% | 10.83% | 4.20% |
| 7/1/1983 | 14.80% | 10.77% | 4.03% |
| 7/1/1983 | 14.90% | 10.77% | 4.13% |
| 7/8/1983 | 16.25% | 10.75% | 5.50% |
| 7/13/1983 | 13.20% | 10.75% | 2.45% |
| 7/19/1983 | 15.00% | 10.74% | 4.26% |
| 7/19/1983 | 15.10% | 10.74% | 4.36% |
| 7/25/1983 | 16.25% | 10.73% | 5.52% |
| 7/28/1983 | 15.90% | 10.74% | 5.16% |
| 8/3/1983 | 16.34% | 10.75% | 5.59% |
| 8/3/1983 | 16.50% | 10.75% | 5.75% |
| 8/19/1983 | 15.00% | 10.80% | 4.20% |
| 8/22/1983 | 15.50% | 10.80% | 4.70% |
| 8/22/1983 | 16.40% | 10.80% | 5.60% |
| 8/31/1983 | 14.75% | 10.85% | 3.90% |
| 9/7/1983 | 15.00% | 10.87% | 4.13% |
| 9/14/1983 | 15.78% | 10.89% | 4.89% |
| 9/16/1983 | 15.00% | 10.90% | 4.10% |
| 9/19/1983 | 14.50% | 10.91% | 3.59% |
| 9/20/1983 | 16.50% | 10.91% | 5.59% |
| 9/28/1983 | 14.50% | 10.94% | 3.56% |
| 9/29/1983 | 15.50% | 10.95% | 4.55% |
| 9/30/1983 | 15.25% | 10.95% | 4.30% |
| 9/30/1983 | 16.15% | 10.95% | 5.20% |
| 10/4/1983 | 14.80% | 10.96% | 3.84% |
| 10/7/1983 | 16.00% | 10.97% | 5.03% |
| 10/13/1983 | 15.52% | 10.99% | 4.53% |
| 10/17/1983 | 15.50% | 11.00% | 4.50% |
| 10/18/1983 | 14.50% | 11.00% | 3.50% |
| 10/19/1983 | 16.25% | 11.01% | 5.24% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/19/1983 | 16.50% | 11.01% | 5.49% |
| 10/26/1983 | 15.00% | 11.04% | 3.96% |
| 10/27/1983 | 15.20% | 11.04% | 4.16% |
| 11/1/1983 | 16.00% | 11.06% | 4.94% |
| 11/9/1983 | 14.90% | 11.09% | 3.81% |
| 11/10/1983 | 14.35% | 11.10% | 3.25% |
| 11/23/1983 | 16.00% | 11.13% | 4.87% |
| 11/23/1983 | 16.15% | 11.13% | 5.02% |
| 11/30/1983 | 15.00% | 11.14% | 3.86% |
| 12/5/1983 | 15.25% | 11.15% | 4.10% |
| 12/6/1983 | 15.07% | 11.16% | 3.91% |
| 12/8/1983 | 15.90% | 11.16% | 4.74% |
| 12/9/1983 | 14.75% | 11.17% | 3.58% |
| 12/12/1983 | 14.50% | 11.18% | 3.32% |
| 12/15/1983 | 15.56% | 11.20% | 4.36% |
| 12/19/1983 | 14.80% | 11.21% | 3.59% |
| 12/20/1983 | 14.69% | 11.22% | 3.47% |
| 12/20/1983 | 16.00% | 11.22% | 4.78% |
| 12/20/1983 | 16.25% | 11.22% | 5.03% |
| 12/22/1983 | 14.75% | 11.23% | 3.52% |
| 12/22/1983 | 15.75% | 11.23% | 4.52% |
| 1/3/1984 | 14.75% | 11.27% | 3.48% |
| 1/10/1984 | 15.90% | 11.30% | 4.60% |
| 1/12/1984 | 15.60% | 11.31% | 4.29% |
| 1/18/1984 | 13.75% | 11.33% | 2.42% |
| 1/19/1984 | 15.90% | 11.33% | 4.57% |
| 1/30/1984 | 16.10% | 11.37% | 4.73% |
| 1/31/1984 | 15.25% | 11.38% | 3.87% |
| 2/1/1984 | 14.80% | 11.39% | 3.41% |
| 2/6/1984 | 13.75% | 11.41% | 2.34% |
| 2/6/1984 | 14.75% | 11.41% | 3.34% |
| 2/9/1984 | 15.25% | 11.43% | 3.82% |
| 2/15/1984 | 15.70% | 11.45% | 4.25% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/22/1984 | 14.75% | 11.48% | 3.27% |
| 2/28/1984 | 14.50% | 11.52% | 2.98% |
| 3/2/1984 | 14.25% | 11.54% | 2.71% |
| 3/20/1984 | 16.00% | 11.65% | 4.35% |
| 3/23/1984 | 15.50% | 11.67% | 3.83% |
| 3/26/1984 | 14.71% | 11.68% | 3.03% |
| 4/2/1984 | 15.50% | 11.72% | 3.78% |
| 4/6/1984 | 14.74% | 11.76% | 2.98% |
| 4/11/1984 | 15.72% | 11.78% | 3.94% |
| 4/17/1984 | 15.00% | 11.81% | 3.19% |
| 4/18/1984 | 16.20% | 11.82% | 4.38% |
| 4/25/1984 | 14.64% | 11.85% | 2.79% |
| 4/30/1984 | 14.40% | 11.88% | 2.52% |
| 5/16/1984 | 14.69% | 11.99% | 2.70% |
| 5/16/1984 | 15.00% | 11.99% | 3.01% |
| 5/22/1984 | 14.40% | 12.02% | 2.38% |
| 5/29/1984 | 15.10% | 12.06% | 3.04% |
| 6/13/1984 | 15.25% | 12.16% | 3.09% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/15/1984 | 15.60% | 12.17% | 3.43% |
| 6/22/1984 | 16.25% | 12.21% | 4.04% |
| 6/29/1984 | 15.25% | 12.26% | 2.99% |
| 7/2/1984 | 13.35% | 12.27% | 1.08% |
| 7/10/1984 | 16.00% | 12.31% | 3.69% |
| 7/12/1984 | 16.50% | 12.33% | 4.17% |
| 7/13/1984 | 16.25% | 12.34% | 3.91% |
| 7/17/1984 | 14.14% | 12.35% | 1.79% |
| 7/18/1984 | 15.30% | 12.36% | 2.94% |
| 7/18/1984 | 15.50% | 12.36% | 3.14% |
| 7/19/1984 | 14.30% | 12.37% | 1.93% |
| 7/24/1984 | 16.79% | 12.40% | 4.39% |
| 7/31/1984 | 16.00% | 12.43% | 3.57% |
| 8/3/1984 | 14.25% | 12.45% | 1.80% |
| 8/17/1984 | 14.30% | 12.49% | 1.81% |
| 8/20/1984 | 15.00% | 12.49% | 2.51% |
| 8/27/1984 | 16.30% | 12.51% | 3.79% |
| 8/31/1984 | 15.55% | 12.53% | 3.02% |
| 9/6/1984 | 16.00% | 12.54% | 3.46% |
| 9/10/1984 | 14.75% | 12.55% | 2.20% |
| 9/13/1984 | 15.00% | 12.55% | 2.45% |
| 9/17/1984 | 17.38% | 12.56% | 4.82% |
| 9/26/1984 | 14.50% | 12.57% | 1.93% |
| 9/28/1984 | 15.00% | 12.57% | 2.43% |
| 9/28/1984 | 16.25% | 12.57% | 3.68% |
| 10/9/1984 | 14.75% | 12.58% | 2.17% |
| 10/12/1984 | 15.60% | 12.59% | 3.01% |
| 10/22/1984 | 15.00% | 12.59% | 2.41% |
| 10/26/1984 | 16.40% | 12.59% | 3.81% |
| 10/31/1984 | 16.25% | 12.59% | 3.66% |
| 11/7/1984 | 15.60% | 12.58% | 3.02% |
| 11/9/1984 | 16.00% | 12.58% | 3.42% |
| 11/14/1984 | 15.75% | 12.59% | 3.16% |
| 11/20/1984 | 15.25% | 12.58% | 2.67% |
| 11/20/1984 | 15.92% | 12.58% | 3.34% |
| 11/23/1984 | 15.00% | 12.58% | 2.42% |
| 11/28/1984 | 16.15% | 12.57% | 3.58% |
| 12/3/1984 | 15.80% | 12.57% | 3.23% |
| 12/4/1984 | 16.50% | 12.56% | 3.94% |
| 12/18/1984 | 16.40% | 12.54% | 3.86% |
| 12/19/1984 | 14.75% | 12.53% | 2.22% |
| 12/19/1984 | 15.00% | 12.53% | 2.47% |
| 12/20/1984 | 16.00% | 12.53% | 3.47% |
| 12/28/1984 | 16.00% | 12.50% | 3.50% |
| 1/3/1985 | 14.75% | 12.49% | 2.26% |
| 1/10/1985 | 15.75% | 12.47% | 3.28% |
| 1/11/1985 | 16.30% | 12.46% | 3.84% |
| 1/23/1985 | 15.80% | 12.43% | 3.37% |
| 1/24/1985 | 15.82% | 12.43% | 3.39% |
| 1/25/1985 | 16.75% | 12.42% | 4.33% |
| 1/30/1985 | 14.90% | 12.40% | 2.50% |
| 1/31/1985 | 14.75% | 12.39% | 2.36% |
| 2/8/1985 | 14.47% | 12.35% | 2.12% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/1/1985 | 13.84% | 12.30% | 1.54% |
| 3/8/1985 | 16.85% | 12.28% | 4.57% |
| 3/14/1985 | 15.50% | 12.25% | 3.25% |
| 3/15/1985 | 15.62% | 12.25% | 3.37% |
| 3/29/1985 | 15.62% | 12.16% | 3.46% |
| 4/3/1985 | 14.60% | 12.13% | 2.47% |
| 4/9/1985 | 15.50% | 12.10% | 3.40% |
| 4/16/1985 | 15.70% | 12.05% | 3.65% |
| 4/22/1985 | 14.00% | 12.01% | 1.99% |
| 4/26/1985 | 15.50% | 11.97% | 3.53% |
| 4/29/1985 | 15.00% | 11.96% | 3.04% |
| 5/2/1985 | 14.68% | 11.93% | 2.75% |
| 5/8/1985 | 15.62% | 11.88% | 3.74% |
| 5/10/1985 | 16.50% | 11.86% | 4.64% |
| 5/29/1985 | 14.61% | 11.73% | 2.88% |
| 5/31/1985 | 16.00% | 11.71% | 4.29% |
| 6/14/1985 | 15.50% | 11.60% | 3.90% |
| 7/9/1985 | 15.00% | 11.44% | 3.56% |
| 7/16/1985 | 14.50% | 11.39% | 3.11% |
| 7/26/1985 | 14.50% | 11.32% | 3.18% |
| 8/2/1985 | 14.80% | 11.29% | 3.51% |
| 8/7/1985 | 15.00% | 11.26% | 3.74% |
| 8/28/1985 | 14.25% | 11.15% | 3.10% |
| 8/28/1985 | 15.50% | 11.15% | 4.35% |
| 8/29/1985 | 14.50% | 11.14% | 3.36% |
| 9/9/1985 | 14.60% | 11.11% | 3.49% |
| 9/9/1985 | 14.90% | 11.11% | 3.79% |
| 9/17/1985 | 14.90% | 11.08% | 3.82% |
| 9/23/1985 | 15.00% | 11.06% | 3.94% |
| 9/27/1985 | 15.50% | 11.04% | 4.46% |
| 9/27/1985 | 15.80% | 11.04% | 4.76% |
| 10/2/1985 | 14.00% | 11.03% | 2.97% |
| 10/2/1985 | 14.75% | 11.03% | 3.72% |
| 10/3/1985 | 15.25% | 11.03% | 4.22% |
| 10/24/1985 | 15.40% | 10.96% | 4.44% |
| 10/24/1985 | 15.82% | 10.96% | 4.86% |
| 10/24/1985 | 15.85% | 10.96% | 4.89% |
| 10/28/1985 | 16.00% | 10.95% | 5.05% |
| 10/29/1985 | 16.65% | 10.94% | 5.71% |
| 10/31/1985 | 15.06% | 10.93% | 4.13% |
| 11/4/1985 | 14.50% | 10.91% | 3.59% |
| 11/7/1985 | 15.50% | 10.89% | 4.61% |
| 11/8/1985 | 14.30% | 10.89% | 3.41% |
| 12/12/1985 | 14.75% | 10.73% | 4.02% |
| 12/18/1985 | 15.00% | 10.69% | 4.31% |
| 12/20/1985 | 14.50% | 10.66% | 3.84% |
| 12/20/1985 | 14.50% | 10.66% | 3.84% |
| 12/20/1985 | 15.00% | 10.66% | 4.34% |
| 1/24/1986 | 15.40% | 10.40% | 5.00% |
| 1/31/1986 | 15.00% | 10.35% | 4.65% |
| 2/5/1986 | 15.00% | 10.32% | 4.68% |
| 2/5/1986 | 15.75% | 10.32% | 5.43% |
| 2/10/1986 | 13.30% | 10.29% | 3.01% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 2/11/1986 | 12.50% | 10.27% | 2.23% |
| 2/14/1986 | 14.40% | 10.24% | 4.16% |
| 2/18/1986 | 16.00% | 10.22% | 5.78% |
| 2/24/1986 | 14.50% | 10.17% | 4.33% |
| 2/26/1986 | 14.00% | 10.15% | 3.85% |
| 3/5/1986 | 14.90% | 10.07% | 4.83% |
| 3/11/1986 | 14.50% | 10.01% | 4.49% |
| 3/12/1986 | 13.50% | 10.00% | 3.50% |
| 3/27/1986 | 14.10% | 9.85% | 4.25% |
| 3/31/1986 | 13.50% | 9.84% | 3.66% |
| 4/1/1986 | 14.00% | 9.82% | 4.18% |
| 4/2/1986 | 15.50% | 9.81% | 5.69% |
| 4/4/1986 | 15.00% | 9.78% | 5.22% |
| 4/14/1986 | 13.40% | 9.68% | 3.72% |
| 4/23/1986 | 15.00% | 9.57% | 5.43% |
| 5/16/1986 | 14.50% | 9.31% | 5.19% |
| 5/16/1986 | 14.50% | 9.31% | 5.19% |
| 5/29/1986 | 13.90% | 9.19% | 4.71% |
| 5/30/1986 | 15.10% | 9.17% | 5.93% |
| 6/2/1986 | 12.81% | 9.16% | 3.65% |
| 6/11/1986 | 14.00% | 9.06% | 4.94% |
| 6/24/1986 | 16.63% | 8.93% | 7.70% |
| 6/26/1986 | 12.00% | 8.90% | 3.10% |
| 6/26/1986 | 14.75% | 8.90% | 5.85% |
| 6/30/1986 | 13.00% | 8.86% | 4.14% |
| 7/10/1986 | 14.34% | 8.74% | 5.60% |
| 7/11/1986 | 12.75% | 8.72% | 4.03% |
| 7/14/1986 | 12.60% | 8.71% | 3.89% |
| 7/17/1986 | 12.40% | 8.65% | 3.75% |
| 7/25/1986 | 14.25% | 8.56% | 5.69% |
| 8/6/1986 | 13.50% | 8.43% | 5.07% |
| 8/14/1986 | 13.50% | 8.34% | 5.16% |
| 9/16/1986 | 12.75% | 8.06% | 4.69% |
| 9/19/1986 | 13.25% | 8.02% | 5.23% |
| 10/1/1986 | 14.00% | 7.94% | 6.06% |
| 10/3/1986 | 13.40% | 7.92% | 5.48% |
| 10/31/1986 | 13.50% | 7.77% | 5.73% |
| 11/5/1986 | 13.00% | 7.74% | 5.26% |
| 12/3/1986 | 12.90% | 7.58% | 5.32% |
| 12/4/1986 | 14.44% | 7.57% | 6.87% |
| 12/16/1986 | 13.60% | 7.52% | 6.08% |
| 12/22/1986 | 13.80% | 7.50% | 6.30% |
| 12/30/1986 | 13.00% | 7.49% | 5.51% |
| 1/2/1987 | 13.00% | 7.48% | 5.52% |
| 1/12/1987 | 12.40% | 7.46% | 4.94% |
| 1/27/1987 | 12.71% | 7.46% | 5.25% |
| 3/2/1987 | 12.47% | 7.47% | 5.00% |
| 3/3/1987 | 13.60% | 7.47% | 6.13% |
| 3/4/1987 | 12.38% | 7.47% | 4.91% |
| 3/10/1987 | 13.50% | 7.47% | 6.03% |
| 3/13/1987 | 13.00% | 7.47% | 5.53% |
| 3/31/1987 | 13.00% | 7.46% | 5.54% |
| 4/6/1987 | 13.00% | 7.47% | 5.53% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 4/14/1987 | 12.50% | 7.49% | 5.01% |
| 4/16/1987 | 14.50% | 7.50% | 7.00% |
| 4/27/1987 | 12.00% | 7.54% | 4.46% |
| 5/5/1987 | 12.85% | 7.58% | 5.27% |
| 5/12/1987 | 12.65% | 7.62% | 5.03% |
| 5/28/1987 | 13.50% | 7.70% | 5.80% |
| 6/15/1987 | 13.20% | 7.78% | 5.42% |
| 6/29/1987 | 15.00% | 7.84% | 7.16% |
| 6/30/1987 | 12.50% | 7.84% | 4.66% |
| 7/8/1987 | 12.00% | 7.86% | 4.14% |
| 7/10/1987 | 12.90% | 7.87% | 5.03% |
| 7/15/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 15.00% | 7.88% | 7.12% |
| 7/27/1987 | 13.00% | 7.92% | 5.08% |
| 7/27/1987 | 13.40% | 7.92% | 5.48% |
| 7/27/1987 | 13.50% | 7.92% | 5.58% |
| 7/31/1987 | 12.98% | 7.95% | 5.03% |
| 8/26/1987 | 12.63% | 8.06% | 4.57% |
| 8/26/1987 | 12.75% | 8.06% | 4.69% |
| 8/27/1987 | 13.25% | 8.07% | 5.18% |
| 9/9/1987 | 13.00% | 8.14% | 4.86% |
| 9/30/1987 | 12.75% | 8.31% | 4.44% |
| 9/30/1987 | 13.00% | 8.31% | 4.69% |
| 10/2/1987 | 11.50% | 8.33% | 3.17% |
| 10/15/1987 | 13.00% | 8.44% | 4.56% |
| 11/2/1987 | 13.00% | 8.55% | 4.45% |
| 11/19/1987 | 13.00% | 8.64% | 4.36% |
| 11/30/1987 | 12.00% | 8.69% | 3.31% |
| 12/3/1987 | 14.20% | 8.71% | 5.49% |
| 12/15/1987 | 13.25% | 8.78% | 4.47% |
| 12/16/1987 | 13.50% | 8.79% | 4.71% |
| 12/16/1987 | 13.72% | 8.79% | 4.93% |
| 12/17/1987 | 11.75% | 8.80% | 2.95% |
| 12/18/1987 | 13.50% | 8.80% | 4.70% |
| 12/21/1987 | 12.01% | 8.81% | 3.20% |
| 12/22/1987 | 12.00% | 8.82% | 3.18% |
| 12/22/1987 | 12.00% | 8.82% | 3.18% |
| 12/22/1987 | 12.75% | 8.82% | 3.93% |
| 12/22/1987 | 13.00% | 8.82% | 4.18% |
| 1/20/1988 | 13.80% | 8.94% | 4.86% |
| 1/26/1988 | 13.90% | 8.96% | 4.94% |
| 1/29/1988 | 13.20% | 8.96% | 4.24% |
| 2/4/1988 | 12.60% | 8.96% | 3.64% |
| 3/1/1988 | 11.56% | 8.94% | 2.62% |
| 3/23/1988 | 12.87% | 8.92% | 3.95% |
| 3/24/1988 | 11.24% | 8.92% | 2.32% |
| 3/30/1988 | 12.72% | 8.92% | 3.80% |
| 4/1/1988 | 12.50% | 8.92% | 3.58% |
| 4/7/1988 | 13.25% | 8.93% | 4.32% |
| 4/25/1988 | 10.96% | 8.96% | 2.00% |
| 5/3/1988 | 12.91% | 8.98% | 3.93% |
| 5/11/1988 | 13.50% | 8.99% | 4.51% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 5/16/1988 | 13.00% | 8.99% | 4.01% |
| 6/30/1988 | 12.75% | 8.99% | 3.76% |
| 7/1/1988 | 12.75% | 8.99% | 3.76% |
| 7/20/1988 | 13.40% | 8.96% | 4.44% |
| 8/5/1988 | 12.75% | 8.91% | 3.84% |
| 8/23/1988 | 11.70% | 8.93% | 2.77% |
| 8/29/1988 | 12.75% | 8.94% | 3.81% |
| 8/30/1988 | 13.50% | 8.94% | 4.56% |
| 9/8/1988 | 12.60% | 8.95% | 3.65% |
| 10/13/1988 | 13.10% | 8.93% | 4.17% |
| 12/19/1988 | 13.00% | 9.02% | 3.98% |
| 12/20/1988 | 12.25% | 9.02% | 3.23% |
| 12/20/1988 | 13.00% | 9.02% | 3.98% |
| 12/21/1988 | 12.90% | 9.02% | 3.88% |
| 12/27/1988 | 13.00% | 9.03% | 3.97% |
| 12/28/1988 | 13.10% | 9.03% | 4.07% |
| 12/30/1988 | 13.40% | 9.04% | 4.36% |
| 1/27/1989 | 13.00% | 9.06% | 3.94% |
| 1/31/1989 | 13.00% | 9.06% | 3.94% |
| 2/17/1989 | 13.00% | 9.05% | 3.95% |
| 2/20/1989 | 12.40% | 9.05% | 3.35% |
| 3/1/1989 | 12.76% | 9.05% | 3.71% |
| 3/8/1989 | 13.00% | 9.05% | 3.95% |
| 3/30/1989 | 14.00% | 9.05% | 4.95% |
| 4/5/1989 | 14.20% | 9.05% | 5.15% |
| 4/18/1989 | 13.00% | 9.05% | 3.95% |
| 5/5/1989 | 12.40% | 9.05% | 3.35% |
| 6/2/1989 | 13.20% | 9.00% | 4.20% |
| 6/8/1989 | 13.50% | 8.98% | 4.52% |
| 6/27/1989 | 13.25% | 8.91% | 4.34% |
| 6/30/1989 | 13.00% | 8.90% | 4.10% |
| 8/14/1989 | 12.50% | 8.77% | 3.73% |
| 9/28/1989 | 12.25% | 8.63% | 3.62% |
| 10/24/1989 | 12.50% | 8.54% | 3.96% |
| 11/9/1989 | 13.00% | 8.48% | 4.52% |
| 12/15/1989 | 13.00% | 8.33% | 4.67% |
| 12/20/1989 | 12.90% | 8.31% | 4.59% |
| 12/21/1989 | 12.90% | 8.31% | 4.59% |
| 12/27/1989 | 12.50% | 8.29% | 4.21% |
| 12/27/1989 | 13.00% | 8.29% | 4.71% |
| 1/10/1990 | 12.80% | 8.24% | 4.56% |
| 1/11/1990 | 12.90% | 8.23% | 4.67% |
| 1/17/1990 | 12.80% | 8.22% | 4.58% |
| 1/26/1990 | 12.00% | 8.19% | 3.81% |
| 2/9/1990 | 12.10% | 8.17% | 3.93% |
| 2/24/1990 | 12.86% | 8.15% | 4.71% |
| 3/30/1990 | 12.90% | 8.16% | 4.74% |
| 4/4/1990 | 15.76% | 8.17% | 7.59% |
| 4/12/1990 | 12.52% | 8.18% | 4.34% |
| 4/19/1990 | 12.75% | 8.20% | 4.55% |
| 5/21/1990 | 12.10% | 8.28% | 3.82% |
| 5/29/1990 | 12.40% | 8.30% | 4.10% |
| 5/31/1990 | 12.00% | 8.30% | 3.70% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/4/1990 | 12.90% | 8.30% | 4.60% |
| 6/6/1990 | 12.25% | 8.31% | 3.94% |
| 6/15/1990 | 13.20% | 8.32% | 4.88% |
| 6/20/1990 | 12.92% | 8.32% | 4.60% |
| 6/27/1990 | 12.90% | 8.33% | 4.57% |
| 6/29/1990 | 12.50% | 8.34% | 4.16% |
| 7/6/1990 | 12.10% | 8.34% | 3.76% |
| 7/6/1990 | 12.35% | 8.34% | 4.01% |
| 8/10/1990 | 12.55% | 8.41% | 4.14% |
| 8/16/1990 | 13.21% | 8.43% | 4.78% |
| 8/22/1990 | 13.10% | 8.45% | 4.65% |
| 8/24/1990 | 13.00% | 8.46% | 4.54% |
| 9/26/1990 | 11.45% | 8.59% | 2.86% |
| 10/2/1990 | 13.00% | 8.61% | 4.39% |
| 10/5/1990 | 12.84% | 8.63% | 4.21% |
| 10/19/1990 | 13.00% | 8.67% | 4.33% |
| 10/25/1990 | 12.30% | 8.68% | 3.62% |
| 11/21/1990 | 12.70% | 8.69% | 4.01% |
| 12/13/1990 | 12.30% | 8.67% | 3.63% |
| 12/17/1990 | 12.87% | 8.67% | 4.20% |
| 12/18/1990 | 13.10% | 8.67% | 4.43% |
| 12/19/1990 | 12.00% | 8.66% | 3.34% |
| 12/20/1990 | 12.75% | 8.66% | 4.09% |
| 12/21/1990 | 12.50% | 8.66% | 3.84% |
| 12/27/1990 | 12.79% | 8.66% | 4.13% |
| 1/2/1991 | 13.10% | 8.66% | 4.44% |
| 1/4/1991 | 12.50% | 8.65% | 3.85% |
| 1/15/1991 | 12.75% | 8.65% | 4.10% |
| 1/25/1991 | 11.70% | 8.63% | 3.07% |
| 2/4/1991 | 12.50% | 8.60% | 3.90% |
| 2/7/1991 | 12.50% | 8.59% | 3.91% |
| 2/12/1991 | 13.00% | 8.57% | 4.43% |
| 2/14/1991 | 12.72% | 8.56% | 4.16% |
| 2/22/1991 | 12.80% | 8.55% | 4.25% |
| 3/6/1991 | 13.10% | 8.53% | 4.57% |
| 3/8/1991 | 12.30% | 8.52% | 3.78% |
| 3/8/1991 | 13.00% | 8.52% | 4.48% |
| 4/22/1991 | 13.00% | 8.49% | 4.51% |
| 5/7/1991 | 13.50% | 8.47% | 5.03% |
| 5/13/1991 | 13.25% | 8.47% | 4.78% |
| 5/30/1991 | 12.75% | 8.43% | 4.32% |
| 6/12/1991 | 12.00% | 8.41% | 3.59% |
| 6/25/1991 | 11.70% | 8.38% | 3.32% |
| 6/28/1991 | 12.50% | 8.38% | 4.12% |
| 7/1/1991 | 12.00% | 8.37% | 3.63% |
| 7/3/1991 | 12.50% | 8.36% | 4.14% |
| 7/19/1991 | 12.10% | 8.34% | 3.76% |
| 8/1/1991 | 12.90% | 8.32% | 4.58% |
| 8/16/1991 | 13.20% | 8.29% | 4.91% |
| 9/27/1991 | 12.50% | 8.23% | 4.27% |
| 9/30/1991 | 12.25% | 8.23% | 4.02% |
| 10/17/1991 | 13.00% | 8.20% | 4.80% |
| 10/23/1991 | 12.50% | 8.20% | 4.30% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/23/1991 | 12.55% | 8.20% | 4.35% |
| 10/31/1991 | 11.80% | 8.19% | 3.61% |
| 11/1/1991 | 12.00% | 8.19% | 3.81% |
| 11/5/1991 | 12.25% | 8.19% | 4.06% |
| 11/12/1991 | 12.50% | 8.18% | 4.32% |
| 11/12/1991 | 13.25% | 8.18% | 5.07% |
| 11/25/1991 | 12.40% | 8.18% | 4.22% |
| 11/26/1991 | 11.60% | 8.18% | 3.42% |
| 11/26/1991 | 12.50% | 8.18% | 4.32% |
| 11/27/1991 | 12.10% | 8.18% | 3.92% |
| 12/18/1991 | 12.25% | 8.15% | 4.10% |
| 12/19/1991 | 12.60% | 8.15% | 4.45% |
| 12/19/1991 | 12.80% | 8.15% | 4.65% |
| 12/20/1991 | 12.65% | 8.14% | 4.51% |
| 1/9/1992 | 12.80% | 8.09% | 4.71% |
| 1/16/1992 | 12.75% | 8.07% | 4.68% |
| 1/21/1992 | 12.00% | 8.06% | 3.94% |
| 1/22/1992 | 13.00% | 8.06% | 4.94% |
| 1/27/1992 | 12.65% | 8.05% | 4.60% |
| 1/31/1992 | 12.00% | 8.04% | 3.96% |
| 2/11/1992 | 12.40% | 8.03% | 4.37% |
| 2/25/1992 | 12.50% | 8.01% | 4.49% |
| 3/16/1992 | 11.43% | 7.98% | 3.45% |
| 3/18/1992 | 12.28% | 7.98% | 4.30% |
| 4/2/1992 | 12.10% | 7.95% | 4.15% |
| 4/9/1992 | 11.45% | 7.93% | 3.52% |
| 4/10/1992 | 11.50% | 7.93% | 3.57% |
| 4/14/1992 | 11.50% | 7.92% | 3.58% |
| 5/5/1992 | 11.50% | 7.89% | 3.61% |
| 5/12/1992 | 11.87% | 7.88% | 3.99% |
| 5/12/1992 | 12.46% | 7.88% | 4.58% |
| 6/1/1992 | 12.30% | 7.86% | 4.44% |
| 6/12/1992 | 10.90% | 7.85% | 3.05% |
| 6/26/1992 | 12.35% | 7.85% | 4.50% |
| 6/29/1992 | 11.00% | 7.85% | 3.15% |
| 6/30/1992 | 13.00% | 7.85% | 5.15% |
| 7/13/1992 | 11.90% | 7.84% | 4.06% |
| 7/13/1992 | 13.50% | 7.84% | 5.66% |
| 7/22/1992 | 11.20% | 7.83% | 3.37% |
| 8/3/1992 | 12.00% | 7.81% | 4.19% |
| 8/6/1992 | 12.50% | 7.80% | 4.70% |
| 9/22/1992 | 12.00% | 7.71% | 4.29% |
| 9/28/1992 | 11.40% | 7.71% | 3.69% |
| 9/30/1992 | 11.75% | 7.71% | 4.04% |
| 10/2/1992 | 13.00% | 7.70% | 5.30% |
| 10/12/1992 | 12.20% | 7.70% | 4.50% |
| 10/16/1992 | 13.16% | 7.71% | 5.45% |
| 10/30/1992 | 11.75% | 7.71% | 4.04% |
| 11/3/1992 | 12.00% | 7.71% | 4.29% |
| 12/3/1992 | 11.85% | 7.68% | 4.17% |
| 12/15/1992 | 11.00% | 7.66% | 3.34% |
| 12/16/1992 | 11.90% | 7.66% | 4.24% |
| 12/16/1992 | 12.40% | 7.66% | 4.74% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/17/1992 | 12.00% | 7.66% | 4.34% |
| 12/22/1992 | 12.30% | 7.65% | 4.65% |
| 12/22/1992 | 12.40% | 7.65% | 4.75% |
| 12/29/1992 | 12.25% | 7.63% | 4.62% |
| 12/30/1992 | 12.00% | 7.63% | 4.37% |
| 12/31/1992 | 11.90% | 7.62% | 4.28% |
| 1/12/1993 | 12.00% | 7.61% | 4.39% |
| 1/21/1993 | 11.25% | 7.59% | 3.66% |
| 2/2/1993 | 11.40% | 7.56% | 3.84% |
| 2/15/1993 | 12.30% | 7.52% | 4.78% |
| 2/24/1993 | 11.90% | 7.49% | 4.41% |
| 2/26/1993 | 11.80% | 7.48% | 4.32% |
| 2/26/1993 | 12.20% | 7.48% | 4.72% |
| 4/23/1993 | 11.75% | 7.29% | 4.46% |
| 5/11/1993 | 11.75% | 7.24% | 4.51% |
| 5/14/1993 | 11.50% | 7.24% | 4.26% |
| 5/25/1993 | 11.50% | 7.22% | 4.28% |
| 5/28/1993 | 11.00% | 7.22% | 3.78% |
| 6/3/1993 | 12.00% | 7.21% | 4.79% |
| 6/16/1993 | 11.50% | 7.19% | 4.31% |
| 6/18/1993 | 12.10% | 7.18% | 4.92% |
| 6/25/1993 | 11.67% | 7.17% | 4.50% |
| 7/21/1993 | 11.38% | 7.10% | 4.28% |
| 7/23/1993 | 10.46% | 7.09% | 3.37% |
| 8/24/1993 | 11.50% | 6.95% | 4.55% |
| 9/21/1993 | 10.50% | 6.80% | 3.70% |
| 9/29/1993 | 11.47% | 6.76% | 4.71% |
| 9/30/1993 | 11.60% | 6.76% | 4.84% |
| 11/2/1993 | 10.80% | 6.60% | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | 3.45% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 11/18/1994 | 11.20% | 7.46% | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | 3.55% |
| 6/9/1995 | 11.25% | 7.60% | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | 4.47% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/18/1996 | 11.75% | 6.84% | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | 4.98% |
| 2/20/1997 | 11.80% | 6.82% | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | 7.00% |
| 1/22/2002 | 10.00% | 5.50% | 4.50% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/27/2002 | 10.10% | 5.45% | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | 5.56% |
| 1/13/2004 | 12.00% | 4.95% | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | 6.43% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/29/2004 | 9.85% | 5.08% | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | 5.58% |
| 4/26/2006 | 10.60% | 4.64% | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | 6.91% |
| 6/6/2006 | 10.00% | 4.75% | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 1/11/2007 | 10.90% | 4.95% | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | 5.45% |
| 5/22/2007 | 10.20% | 4.80% | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | 6.29% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 7/31/2008 | 10.70% | 4.51% | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | 5.69% |
| 11/13/2008 | 10.55% | 4.45% | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | 6.68% |
| 10/23/2009 | 10.88% | 4.06% | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/30/2009 | 10.00% | 4.26% | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | 5.42% |
| 8/25/2010 | 9.90% | 4.37% | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | 5.68% |
| 9/16/2010 | 10.00% | 4.32% | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | 5.98% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/15/2010 | 10.44% | 4.15% | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | 5.89% |
| 2/25/2011 | 10.00% | 4.14% | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | 7.06% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 4/4/2012 | 10.00% | 3.29% | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | 6.96% |
| 7/9/2012 | 10.20% | 3.03% | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | 6.86% |
| 9/19/2012 | 9.80% | 2.94% | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | 7.58% |
| 12/21/2012 | 10.20% | 2.87% | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | 7.14% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/14/2013 | 9.30% | 2.88% | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | 6.73% |
| 6/30/2014 | 9.55% | 3.64% | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | 6.30% |
| 8/20/2014 | 9.75% | 3.56% | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | 6.09% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/15/2014 | 10.25% | 3.51% | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | 6.77% |
| 4/23/2015 | 10.20% | 2.87% | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | 7.05% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/30/2016 | 9.90% | 2.53% | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | 7.50% |
| 2/15/2017 | 9.60% | 2.62% | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | 7.53% |
| 4/12/2017 | 9.40% | 2.74% | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 12/5/2017 | 9.50% | 2.88% | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | 6.74% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/14/2017 | 9.65% | 2.86% | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | 6.53% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | 6.39% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 5/2/2019 | 10.00% | 3.11% | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | 6.81% |
| 8/12/2019 | 9.60% | 2.89% | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | 7.40% |
| 11/7/2019 | 9.35% | 2.58% | 6.77% |
| 11/29/2019 | 9.50% | 2.52% | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | 7.04% |
| 1/8/2020 | 10.02% | 2.43% | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | 7.63% |
| 4/27/2020 | 9.25% | 2.02% | 7.23% |
| 5/8/2020 | 9.90% | 1.97% | 7.93% |
| 5/20/2020 | 9.45% | 1.94% | 7.51% |
| 6/29/2020 | 9.70% | 1.85% | 7.85% |
| 6/30/2020 | 9.10% | 1.85% | 7.25% |
| | | | 4.73% |
| | | | 1,630 |

Expected Earnings Analysis

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| | | Expected ROE | Shares Outstanding | | | Adjustment | Adjusted |
| Company | Ticker | 2023-2025 | 2020 | 2023-2025 | % Increase | Factor | ROE |
| ALLETE, Inc. | ALE | 8.0% | 52.75 | 54.25 | 0.56% | 1.003 | 8.02% |
| Alliant Energy Corporation | LNT | 10.5% | 250.00 | 265.00 | 1.17% | 1.006 | 10.56% |
| Ameren Corporation | AEE | 10.0% | 254.00 | 275.00 | 1.60% | 1.008 | 10.08% |
| American Electric Power Company, Inc. | AEP | 10.5% | 495.00 | 530.00 | 1.38% | 1.007 | 10.57% |
| Avangrid, Inc. | AGR | 5.5% | 309.00 | 309.00 | 0.00% | 1.000 | 5.50% |
| Avista Corporation | AVA | 8.0% | 68.70 | 71.00 | 0.66% | 1.003 | 8.03% |
| CMS Energy Corporation | CMS | 13.5% | 287.00 | 300.00 | 0.89% | 1.004 | 13.56% |
| DTE Energy Company | DTE | 10.5% | 193.00 | 205.00 | 1.21% | 1.006 | 10.56% |
| Evergy, Inc | EVRG | 8.0% | 227.00 | 227.00 | 0.00% | 1.000 | 8.00% |
| Hawaiian Electric Industries, Inc. | HE | 9.0% | 110.00 | 114.00 | 0.72% | 1.004 | 9.03% |
| NextEra Energy, Inc. | NEE | 12.5% | 490.00 | 495.00 | 0.20% | 1.001 | 12.51% |
| NorthWestern Corporation | NWE | 8.5% | 51.00 | 53.00 | 0.77% | 1.004 | 8.53% |
| OGE Energy Corp. | OGE | 12.5% | 200.00 | 200.00 | 0.00% | 1.000 | 12.50% |
| Otter Tail Corporation | OTTR | 11.0% | 41.50 | 41.50 | 0.00% | 1.000 | 11.00% |
| Pinnacle West Capital Corporation | PNW | 10.5% | 112.70 | 118.00 | 0.92% | 1.005 | 10.55% |
| PNM Resources, Inc. | PNM | 9.5% | 85.83 | 92.00 | 1.40% | 1.007 | 9.57% |
| Portland General Electric Company | POR | 9.0% | 89.55 | 90.00 | 0.10% | 1.001 | 9.00% |
| Southern Company | SO | 12.5% | 1060.00 | 1090.00 | 0.56% | 1.003 | 12.53% |
| WEC Energy Group, Inc. | WEC | 12.5% | 315.50 | 315.50 | 0.00% | 1.000 | 12.50% |
| Xcel Energy Inc. | XEL | 11.0% | 539.00 | 548.00 | 0.33% | 1.002 | 11.02% |
| | | | | | | Median | 10.55% |
| | | | | | | Mean | 10.18% |

Notes:

[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals = ([3] / [2])^(1/5)-1
[5] Equals (2 x (1 + [4])) / (2 + [4])
[6] Equals [1] x [5]

Duke Energy Progress
Calculation of Daily Returns, YTD Returns, and Annual Volatility
for the Proxy Group and the S&P 500

| | ALLETE, Inc. | | Alliant Energy Corp. | | Ameren Corp. | | American Electric Power Company, Inc. | | Avangrid, Inc. | | Avista Corp. | | CMS Energy Corp. | | DTE Energy Company | | Evergy, Inc. | | Hawaiian Electric Industries, Inc. | | NextEera Energy, Inc | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return |
| 1/31/2020 | 83.48 | | 59.36 | | 82.05 | | 104.22 | | 53.26 | | 50.85 | | 68.51 | | 132.61 | | 72.16 | | 48.91 | | 268.20 | |
| 2/3/2020 | 84.05 | 0.68% | 59.52 | 0.27% | 82.63 | 0.71% | 104.22 | 0.00% | 53.56 | 0.56% | 51.11 | 0.51% | 68.48 | -0.04% | 133.78 | 0.88% | 71.81 | -0.49% | 48.88 | -0.06% | 266.81 | -0.52% |
| 2/4/2020 | 83.30 | -0.89% | 58.66 | -1.44% | 82.27 | -0.44% | 102.87 | -1.30% | 53.12 | -0.82% | 50.76 | -0.68% | 67.37 | -1.62% | 133.10 | -0.51% | 71.00 | -1.13% | 48.38 | -1.02% | 264.54 | -0.85% |
| 2/5/2020 | 83.62 | 0.38% | 58.56 | -0.17% | 82.68 | 0.50% | 102.12 | -0.73% | 53.00 | -0.23% | 51.15 | 0.77% | 67.91 | 0.80% | 134.45 | 1.01% | 71.02 | 0.03% | 48.37 | -0.02% | 266.71 | 0.82% |
| 2/6/2020 | 82.79 | -0.99% | 58.53 | -0.05% | 83.17 | 0.59% | 102.25 | 0.13% | 52.91 | -0.17% | 51.29 | 0.27% | 67.32 | -0.87% | 134.21 | -0.18% | 71.32 | 0.42% | 48.20 | -0.35% | 268.33 | 0.61% |
| 2/7/2020 | 82.04 | -0.91% | 58.33 | -0.34% | 83.60 | 0.52% | 101.34 | -0.89% | 52.63 | -0.53% | 51.17 | -0.23% | 67.14 | -0.27% | 133.61 | -0.45% | 70.87 | -0.63% | 48.14 | -0.12% | 269.54 | 0.45% |
| 2/10/2020 | 82.14 | 0.12% | 58.42 | 0.15% | 83.98 | 0.45% | 101.92 | 0.57% | 52.88 | 0.48% | 51.38 | 0.41% | 67.56 | 0.63% | 133.46 | -0.11% | 70.79 | -0.11% | 48.34 | 0.42% | 271.74 | 0.82% |
| 2/11/2020 | 82.17 | 0.04% | 58.39 | -0.05% | 84.27 | 0.35% | 102.22 | 0.29% | 52.89 | 0.02% | 51.18 | -0.39% | 67.37 | -0.28% | 134.02 | 0.42% | 70.84 | 0.07% | 48.14 | -0.41% | 272.15 | 0.15% |
| 2/12/2020 | 81.89 | -0.34% | 58.66 | 0.46% | 84.57 | 0.36% | 101.79 | -0.42% | 52.75 | -0.26% | 51.19 | 0.02% | 67.36 | -0.01% | 133.75 | -0.20% | 70.74 | -0.14% | 48.55 | 0.85% | 270.26 | -0.69% |
| 2/13/2020 | 81.24 | -0.79% | 59.38 | 1.23% | 85.75 | 1.40% | 102.85 | 1.04% | 53.58 | 1.57% | 51.66 | 0.92% | 67.92 | 0.83% | 133.55 | -0.15% | 71.55 | 1.15% | 49.74 | 2.45% | 275.47 | 1.93% |
| 2/14/2020 | 81.19 | -0.06% | 59.74 | 0.61% | 86.79 | 1.21% | 103.76 | 0.88% | 53.87 | 0.54% | 52.01 | 0.68% | 68.51 | 0.87% | 134.02 | 0.35% | 72.34 | 1.10% | 50.40 | 1.33% | 278.52 | 1.11% |
| 2/18/2020 | 81.36 | 0.21% | 60.17 | 0.71% | 86.75 | -0.05% | 104.33 | 0.55% | 54.90 | 1.91% | 52.12 | 0.21% | 68.86 | 0.51% | 134.65 | 0.47% | 73.88 | 2.13% | 50.30 | -0.20% | 282.04 | 1.26% |
| 2/19/2020 | 80.21 | -1.41% | 59.47 | -1.16% | 85.88 | -1.00% | 103.50 | -0.80% | 54.97 | 0.13% | 52.21 | 0.17% | 68.48 | -0.55% | 134.07 | -0.43% | 73.91 | 0.04% | 49.65 | -1.29% | 274.67 | -2.61% |
| 2/20/2020 | 79.65 | -0.70% | 59.57 | 0.18% | 85.66 | -0.26% | 102.38 | -1.08% | 55.58 | 1.11% | 51.56 | -1.24% | 68.59 | 0.16% | 133.95 | -0.09% | 73.56 | -0.47% | 49.81 | 0.32% | 277.03 | 0.86% |
| 2/21/2020 | 79.81 | 0.20% | 59.14 | -0.72% | 85.34 | -0.37% | 101.71 | -0.65% | 56.04 | 0.83% | 51.19 | -0.72% | 68.45 | -0.20% | 134.96 | 0.75% | 72.91 | -0.88% | 49.75 | -0.12% | 277.59 | 0.20% |
| 2/24/2020 | 79.18 | -0.79% | 58.84 | -0.52% | 84.82 | -0.61% | 100.04 | -1.64% | 56.57 | 0.95% | 50.45 | -1.45% | 68.25 | -0.29% | 132.86 | -1.56% | 71.99 | -1.26% | 49.32 | -0.86% | 273.94 | -1.31% |
| 2/25/2020 | 77.38 | -2.27% | 58.01 | -1.40% | 83.56 | -1.49% | 98.17 | -1.87% | 56.30 | -0.48% | 49.05 | -2.78% | 66.84 | -2.07% | 128.12 | -3.57% | 70.10 | -2.63% | 48.07 | -2.53% | 270.33 | -1.32% |
| 2/26/2020 | 76.27 | -1.43% | 57.83 | -0.31% | 85.21 | 1.97% | 97.43 | -0.75% | 51.85 | -7.90% | 49.49 | 0.90% | 66.44 | -0.60% | 124.73 | -2.65% | 69.58 | -0.74% | 47.03 | -2.16% | 269.47 | -0.32% |
| 2/27/2020 | 73.22 | -4.00% | 54.95 | -4.98% | 81.57 | -4.27% | 91.86 | -5.72% | 49.78 | -3.99% | 48.57 | -1.86% | 62.82 | -5.45% | 118.01 | -5.39% | 67.00 | -3.71% | 44.86 | -4.61% | 255.85 | -5.05% |
| 2/28/2020 | 68.99 | -5.78% | 52.12 | -5.15% | 79.00 | -3.15% | 89.26 | -2.83% | 49.69 | -0.18% | 47.15 | -2.92% | 60.42 | -3.82% | 111.67 | -5.37% | 65.35 | -2.46% | 42.84 | -4.50% | 252.76 | -1.21% |
| 3/2/2020 | 74.39 | 7.83% | 55.36 | 6.22% | 84.42 | 6.86% | 95.09 | 6.53% | 52.00 | 4.65% | 49.62 | 5.24% | 64.14 | 6.16% | 116.64 | 4.45% | 69.39 | 6.18% | 45.09 | 5.25% | 268.35 | 6.17% |
| 3/3/2020 | 73.69 | -0.94% | 54.77 | -1.07% | 83.16 | -1.49% | 95.45 | 0.38% | 51.70 | -0.58% | 49.33 | -0.58% | 64.32 | 0.28% | 113.02 | -3.10% | 68.85 | -0.78% | 44.93 | -0.35% | 265.15 | -1.19% |
| 3/4/2020 | 77.05 | 4.56% | 57.86 | 5.64% | 87.07 | 4.70% | 99.82 | 4.58% | 53.92 | 4.29% | 51.91 | 5.23% | 68.35 | 6.27% | 119.31 | 5.57% | 73.08 | 6.14% | 46.89 | 4.36% | 282.22 | 6.44% |
| 3/5/2020 | 75.31 | -2.26% | 57.39 | -0.81% | 86.05 | -1.17% | 98.79 | -1.03% | 52.17 | -3.25% | 51.38 | -1.02% | 67.73 | -0.91% | 116.26 | -2.56% | 71.61 | -2.01% | 46.30 | -1.26% | 276.16 | -2.15% |
| 3/6/2020 | 76.21 | 1.20% | 57.49 | 0.17% | 85.35 | -0.81% | 97.70 | -1.10% | 51.27 | -1.73% | 52.59 | 2.36% | 67.89 | 0.24% | 116.12 | -0.12% | 69.84 | -2.47% | 46.74 | 0.95% | 271.82 | -1.57% |
| 3/9/2020 | 73.72 | -3.27% | 54.16 | -5.79% | 81.60 | -4.39% | 94.96 | -2.80% | 49.91 | -2.65% | 50.49 | -3.99% | 65.42 | -3.64% | 102.53 | -11.70% | 64.53 | -7.60% | 43.26 | -7.45% | 261.28 | -3.88% |
| 3/10/2020 | 75.47 | 2.37% | 54.00 | -0.30% | 82.59 | 1.21% | 94.72 | -0.25% | 49.81 | -0.20% | 50.42 | -0.14% | 65.51 | 0.14% | 108.01 | 5.34% | 66.76 | 3.46% | 43.24 | -0.05% | 255.73 | -2.12% |
| 3/11/2020 | 69.55 | -7.84% | 51.59 | -4.46% | 80.87 | -2.08% | 89.72 | -5.28% | 47.58 | -4.48% | 48.01 | -4.78% | 63.25 | -3.45% | 104.11 | -3.61% | 62.35 | -6.61% | 42.00 | -2.87% | 241.26 | -5.66% |
| 3/12/2020 | 62.61 | -9.98% | 48.18 | -6.61% | 72.40 | -10.47% | 82.54 | -8.00% | 42.69 | -10.28% | 42.34 | -11.81% | 58.89 | -6.89% | 91.18 | -12.42% | 55.96 | -10.25% | 39.90 | -5.00% | 208.89 | -13.42% |
| 3/13/2020 | 65.01 | 3.83% | 50.90 | 5.65% | 76.15 | 5.18% | 86.47 | 4.76% | 45.80 | 7.29% | 45.00 | 6.28% | 62.39 | 5.94% | 96.44 | 5.77% | 59.09 | 5.59% | 43.69 | 9.50% | 221.56 | 6.07% |
| 3/16/2020 | 55.28 | -14.97% | 47.56 | -6.56% | 65.95 | -13.39% | 81.66 | -5.56% | 42.76 | -6.64% | 43.40 | -3.56% | 56.95 | -8.72% | 83.03 | -13.91% | 49.60 | -16.06% | 43.89 | 0.46% | 201.37 | -9.11% |
| 3/17/2020 | 67.17 | 21.51% | 52.37 | 10.11% | 77.69 | 17.80% | 91.20 | 11.68% | 50.24 | 17.49% | 51.74 | 19.22% | 64.82 | 13.82% | 88.38 | 6.44% | 57.56 | 16.05% | 49.31 | 12.35% | 221.76 | 10.13% |
| 3/18/2020 | 61.41 | -8.58% | 48.97 | -6.49% | 76.15 | -1.98% | 88.28 | -3.20% | 50.17 | -0.14% | 51.29 | -0.87% | 60.64 | -6.45% | 77.00 | -12.88% | 57.71 | 0.26% | 53.32 | 8.13% | 210.64 | -5.01% |
| 3/19/2020 | 63.65 | 3.65% | 45.03 | -8.05% | 71.88 | -5.61% | 80.81 | -8.46% | 46.48 | -7.35% | 46.51 | -9.32% | 56.49 | -6.84% | 85.41 | 10.92% | 55.10 | -4.52% | 48.51 | -9.02% | 207.10 | -1.68% |
| 3/20/2020 | 54.71 | -14.05% | 40.70 | -9.62% | 62.93 | -12.45% | 71.45 | -11.58% | 41.63 | -10.43% | 36.16 | -22.25% | 49.55 | -12.29% | 83.00 | -2.82% | 47.18 | -14.37% | 39.47 | -18.64% | 191.75 | -7.41% |
| 3/23/2020 | 52.24 | -4.51% | 39.99 | -1.74% | 61.37 | -2.48% | 70.00 | -2.03% | 36.14 | -13.19% | 33.04 | -8.63% | 48.51 | -2.10% | 76.81 | -7.46% | 44.92 | -4.79% | 34.33 | -13.02% | 181.66 | -5.26% |
| 3/24/2020 | 57.01 | 9.13% | 43.86 | 9.68% | 65.29 | 6.39% | 72.05 | 2.93% | 37.66 | 4.21% | 38.05 | 15.16% | 51.43 | 6.02% | 86.52 | 12.64% | 50.71 | 12.89% | 38.98 | 13.55% | 206.53 | 13.69% |
| 3/25/2020 | 57.50 | 0.86% | 44.18 | 0.73% | 67.54 | 3.45% | 73.29 | 1.72% | 41.46 | 10.09% | 37.25 | -2.10% | 53.32 | 3.67% | 92.48 | 6.89% | 51.90 | 2.35% | 38.09 | -2.28% | 210.27 | 1.81% |
| 3/26/2020 | 62.32 | 8.38% | 47.90 | 8.42% | 72.79 | 7.77% | 81.80 | 11.61% | 44.85 | 8.18% | 40.26 | 8.08% | 56.94 | 6.79% | 97.98 | 5.95% | 58.16 | 12.06% | 40.75 | 6.98% | 231.10 | 9.91% |
| 3/27/2020 | 61.93 | -0.63% | 47.75 | -0.31% | 74.24 | 1.99% | 83.40 | 1.96% | 43.43 | -3.17% | 40.90 | 1.59% | 58.23 | 2.27% | 97.53 | -0.46% | 57.52 | -1.10% | 41.71 | 2.36% | 231.95 | 0.37% |
| 3/30/2020 | 62.49 | 0.90% | 50.57 | 5.91% | 78.17 | 5.29% | 83.71 | 0.37% | 44.72 | 2.97% | 44.37 | 8.48% | 61.94 | 6.37% | 99.43 | 1.95% | 59.11 | 2.76% | 44.22 | 6.02% | 246.01 | 6.06% |
| 3/31/2020 | 60.68 | -2.90% | 48.29 | -4.51% | 72.83 | -6.83% | 79.98 | -4.46% | 43.78 | -2.10% | 42.49 | -4.24% | 58.75 | -5.15% | 94.97 | -4.49% | 55.05 | -6.87% | 43.05 | -2.65% | 240.62 | -2.19% |
| 4/1/2020 | 56.82 | -6.36% | 44.97 | -6.88% | 67.73 | -7.00% | 74.57 | -6.76% | 41.20 | -5.89% | 39.49 | -7.06% | 55.71 | -5.17% | 88.08 | -7.25% | 51.75 | -5.99% | 40.34 | -6.30% | 218.23 | -9.31% |
| 4/2/2020 | 56.60 | -0.39% | 46.92 | 4.34% | 71.67 | 5.82% | 76.79 | 2.98% | 42.43 | 2.99% | 41.75 | 5.72% | 56.86 | 2.06% | 89.17 | 1.24% | 53.48 | 3.34% | 41.24 | 2.23% | 226.45 | 3.77% |
| 4/3/2020 | 54.51 | -3.69% | 45.15 | -3.77% | 68.75 | -4.07% | 72.50 | -5.59% | 39.89 | -5.99% | 40.60 | -2.75% | 54.55 | -4.06% | 87.13 | -2.29% | 51.80 | -3.14% | 40.00 | -3.01% | 221.64 | -2.12% |
| 4/6/2020 | 59.31 | 8.81% | 47.83 | 5.94% | 74.29 | 8.06% | 78.59 | 8.40% | 41.40 | 3.79% | 42.67 | 5.10% | 58.85 | 7.88% | 96.04 | 10.23% | 57.88 | 11.74% | 42.90 | 7.25% | 234.51 | 5.81% |
| 4/7/2020 | 58.46 | -1.43% | 48.03 | 0.42% | 71.53 | -3.72% | 78.75 | 0.20% | 41.14 | -0.63% | 40.78 | -4.43% | 57.34 | -2.57% | 97.45 | 1.47% | 57.08 | -1.38% | 42.26 | -1.49% | 228.49 | -2.57% |
| 4/8/2020 | 60.55 | 3.58% | 51.23 | 6.66% | 76.01 | 6.26% | 83.30 | 5.78% | 42.95 | 4.40% | 42.03 | 3.07% | 60.64 | 5.76% | 103.84 | 6.56% | 60.86 | 6.62% | 43.60 | 3.17% | 233.50 | 2.19% |
| 4/9/2020 | 61.88 | 2.20% | 53.14 | 3.73% | 79.00 | 3.93% | 86.31 | 3.61% | 45.92 | 6.92% | 45.39 | 7.99% | 62.33 | 2.79% | 111.25 | 7.14% | 63.10 | 3.68% | 45.60 | 4.59% | 245.28 | 5.04% |
| 4/13/2020 | 59.87 | -3.25% | 51.28 | -3.50% | 75.82 | -4.03% | 83.50 | -3.26% | 44.78 | -2.48% | 43.12 | -5.00% | 61.16 | -1.88% | 108.64 | -2.35% | 60.75 | -3.72% | 43.43 | -4.76% | 236.21 | -3.70% |
| 4/14/2020 | 61.04 | 1.95% | 53.62 | 4.56% | 77.17 | 1.78% | 86.25 | 3.29% | 46.06 | 2.86% | 44.60 | 3.43% | 62.27 | 1.81% | 108.34 | -0.28% | 62.54 | 2.95% | 43.53 | 0.23% | 242.38 | 2.61% |
| 4/15/2020 | 57.52 | -5.77% | 51.50 | -3.95% | 75.50 | -2.16% | 83.61 | -3.06% | 44.89 | -2.54% | 43.51 | -2.44% | 60.70 | -2.52% | 104.80 | -3.27% | 60.09 | -3.92% | 41.18 | -5.40% | 237.22 | -2.13% |
| 4/16/2020 | 56.39 | -1.96% | 51.61 | 0.21% | 77.26 | 2.33% | 84.05 | 0.53% | 45.48 | 1.31% | 44.15 | 1.47% | 61.88 | 1.94% | 101.57 | -3.08% | 59.96 | -0.22% | 41.17 | -0.02% | 237.48 | 0.11% |
| 4/17/2020 | 58.35 | 3.48% | 52.87 | 2.44% | 77.83 | 0.74% | 86.38 | 2.77% | 45.99 | 1.12% | 44.51 | 0.82% | 63.17 | 2.08% | 105.85 | 4.21% | 60.98 | 1.70% | 41.98 | 1.97% | 246.26 | 3.70% |
| 4/20/2020 | 54.67 | -6.31% | 49.99 | -5.45% | 73.24 | -5.90% | 82.91 | -4.02% | 44.11 | -4.09% | 43.50 | -2.27% | 59.19 | -6.30% | 100.76 | -4.81% | 59.12 | -3.05% | 40.02 | -4.67% | 237.61 | -3.51% |
| 4/21/2020 | 55.95 | 2.34% | 49.70 | -0.58% | 74.02 | 1.06% | 82.47 | -0.53% | 43.89 | -0.50% | 43.01 | -1.13% | 58.41 | -1.32% | 99.14 | -1.61% | 58.24 | -1.49% | 39.09 | -2.32% | 235.42 | -0.92% |
| 4/22/2020 | 55.78 | -0.30% | 51.03 | 2.68% | 76.78 | 3.73% | 85.00 | 3.07% | 45.37 | 3.37% | 43.21 | 0.47% | 59.99 | 2.71% | 102.36 | 3.25% | 59.55 | 2.25% | 39.84 | 1.92% | 247.17 | 4.99% |
| 4/23/2020 | 56.57 | 1.42% | 50.09 | -1.84% | 74.19 | -3.37% | 83.02 | -2.33% | 44.98 | -0.86% | 42.97 | -0.56% | 59.24 | -1.25% | 101.01 | -1.32% | 57.79 | -2.96% | 39.46 | -0.95% | 241.14 | -2.44% |
| 4/24/2020 | 57.34 | 1.36% | 49.98 | -0.22% | 73.64 | -0.74% | 83.23 | 0.25% | 44.95 | -0.07% | 42.84 | -0.30% | 59.40 | 0.27% | 103.02 | 1.99% | 58.51 | 1.25% | 39.52 | 0.15% | 239.70 | -0.60% |
| 4/27/2020 | 58.61 | 2.21% | 50.34 | 0.72% | 73.42 | -0.30% | 83.62 | 0.47% | 45.57 | 1.38% | 43.31 | 1.10% | 58.00 | -2.36% | 102.68 | -0.33% | 59.26 | 1.28% | 39.99 | 1.19% | 243.60 | 1.63% |
| 4/28/2020 | 60.27 | 2.83% | 50.65 | 0.62% | 74.25 | 1.13% | 84.63 | 1.21% | 44.98 | -1.29% | 43.63 | 0.74% | 59.21 | 2.09% | 106.32 | 3.54% | 60.09 | 1.40% | 40.53 | 1.35% | 239.30 | -1.77% |
| 4/29/2020 | 61.40 | 1.87% | 49.41 | -2.45% | 74.62 | 0.50% | 83.13 | -1.77% | 44.58 | -0.89% | 44.42 | 1.81% | 57.26 | -3.29% | 107.29 | 0.91% | 59.59 | -0.83% | 40.83 | 0.74% | 235.13 | -1.74% |
| 4/30/2020 | 57.56 | -6.25% | 48.55 | -1.74% | 72.75 | -2.51% | 83.11 | -0.02% | 43.00 | -3.54% | 43.04 | -3.11% | 57.09 | -0.30% | 103.74 | -3.31% | 58.43 | -1.95% | 39.47 | -3.33% | 231.12 | -1.71% |
| 5/1/2020 | 55.65 | -3.32% | 47.25 | -2.68% | 71.45 | -1.79% | 81.39 | -2.07% | 41.44 | -3.63% | 40.90 | -4.97% | 55.95 | -2.00% | 100.68 | -2.95% | 55.92 | -4.30% | 38.10 | -3.47% | 227.05 | -1.76% |
| 5/4/2020 | 55.54 | -0.20% | 47.50 | 0.52% | 71.44 | -0.01% | 83.05 | 2.04% | 41.32 | -0.29% | 41.28 | 0.93% | 56.74 | 1.41% | 100.83 | 0.15% | 56.63 | 1.27% | 38.32 | 0.58% | 230.09 | 1.34% |
| 5/5/2020 | 56.55 | 1.82% | 48.02 | 1.11% | 72.15 | 0.99% | 83.31 | 0.31% | 42.71 | 3.36% | 41.44 | 0.39% | 57.16 | 0.74% | 102.41 | 1.57% | 57.29 | 1.17% | 38.05 | -0.70% | 230.10 | 0.00% |
| 5/6/2020 | 52.23 | -7.64% | 46.17 | -3.85% | 69.84 | -3.20% | 78.82 | -5.39% | 41.48 | -2.88% | 39.29 | -5.19% | 54.66 | -4.37% | 100.51 | -1.86% | 54.93 | -4.12% | 36.44 | -4.23% | 222.66 | -3.23% |
| 5/7/2020 | 52.95 | 1.38% | 46.24 | 0.15% | 69.65 | -0.27% | 78.60 | -0.28% | 41.75 | 0.65% | 40.10 | 2.06% | 54.54 | -0.22% | 98.72 | -1.78% | 55.87 | 1.71% | 36.53 | 0.25% | 224.48 | 0.82% |
| 5/8/2020 | 55.78 | 5.34% | 47.99 | 3.78% | 70.86 | 1.74% | 79.86 | 1.60% | 42.48 | 1.75% | 39.93 | -0.42% | 55.29 | 1.38% | 101.26 | 2.57% | 57.50 | 2.92% | 38.19 | 4.54% | 229.73 | 2.34% |
| 5/11/2020 | 54.27 | -2.71% | 47.08 | -1.90% | 70.83 | -0.04% | 79.17 | -0.86% | 41.87 | -1.44% | 39.50 | -1.08% | 55.48 | 0.34% | 98.73 | -2.50% | 55.76 | -3.03% | 37.90 | -0.76% | 227.38 | -1.02% |
| 5/12/2020 | 52.68 | -2.93% | 46.40 | -1.45% | 68.97 | -2.63% | 77.91 | -1.59% | 40.77 | -2.63% | 37.99 | -3.82% | 55.55 | 0.13% | 99.26 | 0.54% | 56.10 | 0.61% | 36.81 | -2.88% | 227.93 | 0.24% |
| 5/13/2020 | 51.92 | -1.44% | 45.86 | -1.15% | 68.35 | -0.90% | 77.73 | -0.23% | 39.99 | -1.91% | 36.35 | -4.32% | 54.63 | -1.66% | 95.96 | -3.32% | 56.52 | 0.75% | 36.34 | -1.28% | 230.12 | 0.96% |
| 5/14/2020 | 50.01 | -3.68% | 45.94 | 0.17% | 68.72 | 0.54% | 78.10 | 0.48% | 40.89 | 2.25% | 36.29 | -0.17% | 54.37 | -0.48% | 98.00 | 2.13% | 56.68 | 0.28% | 36.43 | 0.25% | 232.23 | 0.92% |
| 5/15/2020 | 49.60 | -0.82% | 45.95 | 0.02% | 68.76 | 0.06% | 78.43 | 0.42% | 39.68 | -2.96% | 36.03 | -0.72% | 53.68 | -1.27% | 97.35 | -0.66% | 56.54 | -0.25% | 36.11 | -0.88% | 227.85 | -1.89% |
| 5/18/2020 | 53.49 | 7.84% | 47.74 | 3.90% | 72.23 | 5.05% | 79.88 | 1.85% | 41.00 | 3.33% | 38.29 | 6.27% | 56.09 | 4.49% | 103.24 | 6.05% | 58.92 | 4.21% | 38.28 | 6.01% | 235.45 | 3.34% |
| 5/19/2020 | 52.63 | -1.61% | 46.32 | -2.97% | 70.65 | -2.19% | 77.14 | -3.43% | 40.36 | -1.56% | 36.91 | -3.60% | 55.31 | -1.39% | 102.86 | -0.37% | 57.74 | -2.00% | 37.27 | -2.64% | 230.50 | -2.10% |
| 5/20/2020 | 54.04 | 2.68% | 46.66 | 0.73% | 70.33 | -0.45% | 77.75 | 0.79% | 40.51 | 0.37% | 38.09 | 3.20% | 55.44 | 0.24% | 103.25 | 0.38% | 59.11 | 2.37% | 38.23 | 2.58% | 232.79 | 0.99% |
| 5/21/2020 | 53.43 | -1.13% | 46.03 | -1.35% | 69.30 | -1.46% | 77.37 | -0.49% | 40.28 | -0.57% | 38.12 | 0.08% | 54.74 | -1.26% | 101.04 | -2.14% | 58.65 | -0.78% | 37.54 | -1.80% | 228.90 | -1.67% |
| 5/22/2020 | 53.49 | 0.11% | 46.38 | 0.76% | 69.82 | 0.75% | 78.78 | 1.82% | 40.96 | 1.69% | 38.07 | -0.13% | 55.59 | 1.55% | 102.12 | 1.07% | 60.00 | 2.30% | 37.27 | -0.72% | 233.85 | 2.16% |
| 5/26/2020 | 55.42 | 3.61% | 46.91 | 1.14% | 70.76 | 1.35% | 79.92 | 1.45% | 42.08 | 2.73% | 38.82 | 1.97% | 55.68 | 0.16% | 105.35 | 3.16% | 59.89 | -0.18% | 38.22 | 2.55% | 234.31 | 0.20% |
| 5/27/2020 | 58.21 | 5.03% | 47.33 | 0.90% | 70.51 | -0.35% | 81.44 | 1.90% | 42.90 | 1.95% | 38.92 | 0.26% | 55.97 | 0.52% | 106.50 | 1.09% | 60.93 | 1.74% | 38.38 | 0.42% | 241.13 | 2.91% |
| 5/28/2020 | 57.46 | -1.29% | 48.86 | 3.23% | 73.94 | 4.86% | 85.10 | 4.49% | 43.96 | 2.47% | 38.87 | -0.13% | 57.93 | 3.50% | 107.76 | 1.18% | 62.31 | 2.26% | 39.22 | 2.19% | 251.36 | 4.24% |
| 5/29/2020 | 58.73 | 2.21% | 49.36 | 1.02% | 74.73 | 1.07% | 85.25 | 0.18% | 44.48 | 1.18% | 39.17 | 0.77% | 58.58 | 1.12% | 107.57 | -0.18% | 61.69 | -1.00% | 39.46 | 0.61% | 255.56 | 1.67% |
| 6/1/2020 | 59.20 | 0.80% | 49.46 | 0.20% | 74.37 | -0.48% | 86.14 | 1.04% | 44.92 | 0.99% | 38.92 | -0.64% | 59.01 | 0.73% | 108.42 | 0.79% | 62.96 | 2.06% | 38.99 | -1.19% | 255.65 | 0.04% |
| 6/2/2020 | 59.89 | 1.17% | 50.16 | 1.42% | 74.91 | 0.73% | 85.98 | -0.19% | 45.77 | 1.89% | 39.30 | 0.98% | 59.50 | 0.83% | 110.41 | 1.84% | 63.04 | 0.13% | 38.58 | -1.05% | 256.60 | 0.37% |
| 6/3/2020 | 61.09 | 2.00% | 51.04 | 1.75% | 76.08 | 1.56% | 86.99 | 1.17% | 46.17 | 0.87% | 40.02 | 1.83% | 60.14 | 1.08% | 113.04 | 2.38% | 63.41 | 0.59% | 39.46 | 2.28% | 259.58 | 1.16% |
| 6/4/2020 | 60.57 | -0.85% | 50.10 | -1.84% | 73.99 | -2.75% | 84.40 | -2.98% | 45.15 | -2.21% | 39.95 | -0.17% | 58.79 | -2.24% | 111.13 | -1.69% | 62.41 | -1.58% | 38.90 | -1.42% | 251.89 | -2.96% |
| 6/5/2020 | 62.88 | 3.81% | 50.64 | 1.08% | 75.58 | 2.15% | 85.51 | 1.32% | 44.73 | -0.93% | 39.65 | -0.75% | 59.44 | 1.11% | 114.87 | 3.37% | 63.06 | 1.04% | 39.67 | 1.98% | 254.38 | 0.99% |
| 6/8/2020 | 63.66 | 1.24% | 52.32 | 3.32% | 77.22 | 2.17% | 87.91 | 2.81% | 46.61 | 4.20% | 39.56 | -0.23% | 60.98 | 2.59% | 117.41 | 2.21% | 65.10 | 3.24% | 40.54 | 2.19% | 260.48 | 2.40% |
| 6/9/2020 | 63.19 | -0.74% | 50.77 | -2.96% | 75.27 | -2.53% | 85.91 | -2.28% | 44.86 | -3.75% | 39.09 | -1.19% | 60.29 | -1.13% | 115.00 | -2.05% | 63.57 | -2.35% | 40.09 | -1.11% | 258.67 | -0.69% |
| 6/10/2020 | 62.12 | -1.69% | 50.72 | -0.10% | 74.86 | -0.54% | 85.37 | -0.63% | 44.91 | 0.11% | 38.59 | -1.28% | 59.90 | -0.65% | 112.94 | -1.79% | 63.43 | -0.22% | 39.64 | -1.12% | 256.79 | -0.73% |
| 6/11/2020 | 57.29 | -7.78% | 48.69 | -4.00% | 71.84 | -4.03% | 81.76 | -4.23% | 42.42 | -5.54% | 36.19 | -6.22% | 58.11 | -2.99% | 105.00 | -7.03% | 60.95 | -3.91% | 37.01 | -6.63% | 248.33 | -3.29% |
| 6/12/2020 | 57.73 | 0.77% | 48.55 | -0.29% | 71.75 | -0.13% | 81.80 | 0.05% | 42.26 | -0.38% | 36.48 | 0.80% | 58.30 | 0.33% | 105.07 | 0.07% | 60.08 | -1.43% | 37.04 | 0.08% | 246.91 | -0.57% |
| 6/15/2020 | 58.41 | 1.18% | 48.92 | 0.76% | 72.34 | 0.82% | 81.76 | -0.05% | 42.93 | 1.59% | 37.55 | 2.93% | 58.47 | 0.29% | 106.02 | 0.90% | 59.35 | -1.22% | 37.01 | -0.08% | 248.57 | 0.67% |
| 6/16/2020 | 57.95 | -0.79% | 49.00 | 0.16% | 72.55 | 0.29% | 81.60 | -0.20% | 42.66 | -0.63% | 37.48 | -0.19% | 59.13 | 1.13% | 107.98 | 1.85% | 59.97 | 1.04% | 37.05 | 0.11% | 248.17 | -0.16% |
| 6/17/2020 | 56.48 | -2.54% | 48.91 | -0.18% | 72.46 | -0.12% | 82.25 | 0.80% | 42.20 | -1.08% | 37.14 | -0.91% | 59.12 | -0.02% | 107.18 | -0.74% | 59.88 | -0.15% | 36.39 | -1.78% | 249.00 | 0.33% |
| 6/18/2020 | 56.31 | -0.30% | 49.03 | 0.25% | 72.46 | 0.00% | 81.77 | -0.58% | 41.73 | -1.11% | 36.94 | -0.54% | 59.03 | -0.15% | 107.73 | 0.51% | 60.56 | 1.14% | 36.13 | -0.71% | 248.93 | -0.03% |
| 6/19/2020 | 54.48 | -3.25% | 47.99 | -2.12% | 69.80 | -3.67% | 79.71 | -2.52% | 40.90 | -1.99% | 35.33 | -4.36% | 57.93 | -1.86% | 103.76 | -3.69% | 59.35 | -2.00% | 35.82 | -0.86% | 242.21 | -2.70% |
| 6/22/2020 | 54.71 | 0.42% | 48.49 | 1.03% | 70.62 | 1.17% | 80.62 | 1.14% | 41.48 | 1.42% | 35.52 | 0.54% | 58.77 | 1.45% | 106.75 | 2.88% | 59.92 | 0.96% | 36.18 | 1.01% | 247.04 | 1.99% |
| 6/23/2020 | 54.26 | -0.82% | 47.89 | -1.23% | 70.00 | -0.88% | 80.95 | 0.41% | 41.35 | -0.31% | 34.89 | -1.77% | 57.82 | -1.62% | 107.26 | 0.48% | 59.64 | -0.47% | 35.65 | -1.46% | 243.21 | -1.55% |
| 6/24/2020 | 53.84 | -0.77% | 47.12 | -1.61% | 69.46 | -0.77% | 80.71 | -0.30% | 41.42 | 0.17% | 35.35 | 1.32% | 57.40 | -0.73% | 105.27 | -1.86% | 59.04 | -1.01% | 35.50 | -0.42% | 241.67 | -0.63% |
| 6/25/2020 | 53.00 | -1.56% | 46.77 | -0.74% | 68.81 | -0.94% | 79.30 | -1.75% | 41.53 | 0.27% | 35.07 | -0.79% | 56.77 | -1.10% | 104.92 | -0.33% | 58.98 | -0.10% | 35.43 | -0.20% | 239.16 | -1.04% |
| 6/26/2020 | 52.48 | -0.98% | 47.05 | 0.60% | 68.90 | 0.13% | 78.00 | -1.64% | 41.08 | -1.08% | 33.77 | -3.71% | 56.52 | -0.44% | 104.12 | -0.76% | 58.11 | -1.48% | 35.10 | -0.93% | 236.22 | -1.23% |
| 6/29/2020 | 54.58 | 4.00% | 47.40 | 0.74% | 69.73 | 1.20% | 79.57 | 2.01% | 42.28 | 2.92% | 35.48 | 5.06% | 57.55 | 1.82% | 106.56 | 2.34% | 59.18 | 1.84% | 35.89 | 2.25% | 238.24 | 0.86% |
| 6/30/2020 | 54.61 | 0.05% | 47.84 | 0.93% | 70.36 | 0.90% | 79.64 | 0.09% | 41.98 | -0.71% | 36.39 | 2.56% | 58.42 | 1.51% | 107.50 | 0.88% | 59.29 | 0.19% | 36.06 | 0.47% | 240.17 | 0.81% |
| 7/1/2020 | 55.36 | 1.37% | 48.76 | 1.92% | 72.49 | 3.03% | 82.00 | 2.96% | 43.16 | 2.81% | 36.80 | 1.13% | 59.96 | 2.64% | 110.00 | 2.33% | 61.01 | 2.90% | 36.14 | 0.22% | 246.26 | 2.54% |
| 7/2/2020 | 55.94 | 1.05% | 49.42 | 1.35% | 73.23 | 1.02% | 82.52 | 0.63% | 43.11 | -0.12% | 36.65 | -0.41% | 60.30 | 0.57% | 109.97 | -0.03% | 61.46 | 0.74% | 36.12 | -0.06% | 246.40 | 0.06% |
| 7/6/2020 | 55.52 | -0.75% | 49.00 | -0.85% | 73.34 | 0.15% | 82.12 | -0.48% | 42.45 | -1.53% | 36.13 | -1.42% | 60.03 | -0.45% | 108.43 | -1.40% | 61.46 | 0.00% | 35.72 | -1.11% | 246.96 | 0.23% |
| 7/7/2020 | 56.45 | 1.68% | 48.47 | -1.08% | 73.34 | 0.00% | 82.39 | 0.33% | 42.69 | 0.57% | 35.72 | -1.13% | 59.49 | -0.90% | 107.09 | -1.24% | 60.84 | -1.01% | 35.72 | 0.00% | 246.72 | -0.10% |
| 7/8/2020 | 56.27 | -0.32% | 48.51 | 0.08% | 73.94 | 0.82% | 82.42 | 0.04% | 42.97 | 0.66% | 35.67 | -0.14% | 59.40 | -0.15% | 107.90 | 0.76% | 61.38 | 0.89% | 35.86 | 0.39% | 253.27 | 2.65% |
| 7/9/2020 | 56.28 | 0.02% | 48.25 | -0.54% | 73.65 | -0.39% | 82.02 | -0.49% | 42.54 | -1.00% | 35.19 | -1.35% | 58.99 | -0.69% | 106.67 | -1.14% | 60.87 | -0.83% | 35.54 | -0.89% | 251.99 | -0.51% |
| 7/10/2020 | 58.60 | 4.12% | 49.04 | 1.64% | 74.54 | 1.21% | 84.15 | 2.60% | 43.80 | 2.96% | 36.14 | 2.70% | 59.47 | 0.81% | 107.51 | 0.79% | 61.98 | 1.82% | 36.44 | 2.53% | 259.60 | 3.02% |
| Price 1/31/2020 | 83.48 | | 59.36 | | 82.05 | | 104.22 | | 53.26 | | 50.85 | | 68.51 | | 132.61 | | 72.16 | | 48.91 | | 268.20 | |
| Price 7/10/2020 | 58.60 | | 49.04 | | 74.54 | | 84.15 | | 43.80 | | 36.14 | | 59.47 | | 107.51 | | 61.98 | | 36.44 | | 259.60 | |
| Price Change (1) | -29.80% | | -17.39% | | -9.15% | | -19.26% | | -17.76% | | -28.93% | | -13.20% | | -18.93% | | -14.11% | | -25.50% | | -3.21% | |
| Standard Deviation of Returns | | 4.49% | | 3.39% | | 3.88% | | 3.37% | | 3.90% | | 4.58% | | 3.43% | | 4.23% | | 4.28% | | 4.10% | | 3.64% |
| Annual Volatility (2) | | 71.29% | | 53.77% | | 61.57% | | 53.44% | | 61.86% | | 72.77% | | 54.46% | | 67.23% | | 68.00% | | 65.11% | | 57.71% |

| | Northwestern Corp. | | OGE Energy Corp. | | Otter Tail Corp. | | Pinnacle West Capital Corp. | | PNM Resources, Inc. | | Portland General Electric Company | | Southern Company | | WEC Energy Group, Inc. | | Xcel Energy, Inc. | | Average | | S&P 500 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | Price | Return | | | Price | Return |
| 1/31/2020 | 76.97 | | 45.85 | | 53.56 | | 97.69 | | 54.23 | | 61.50 | | 70.40 | | 99.89 | | 69.19 | | | | 3,225.52 | |
| 2/3/2020 | 77.34 | 0.48% | 45.93 | 0.17% | 54.46 | 1.68% | 98.24 | 0.56% | 54.52 | 0.53% | 61.41 | -0.15% | 70.70 | 0.43% | 100.89 | 1.00% | 69.45 | 0.38% | | | 3,248.93 | 0.73% |
| 2/4/2020 | 76.96 | -0.49% | 45.75 | -0.39% | 53.72 | -1.36% | 97.62 | -0.63% | 54.17 | -0.64% | 60.75 | -1.07% | 69.54 | -1.64% | 99.64 | -1.24% | 69.30 | -0.22% | | | 3,297.59 | 1.50% |
| 2/5/2020 | 77.62 | 0.86% | 45.99 | 0.52% | 54.49 | 1.43% | 98.17 | 0.56% | 54.51 | 0.63% | 60.68 | -0.12% | 69.03 | -0.73% | 100.01 | 0.37% | 69.30 | 0.00% | | | 3,334.69 | 1.13% |
| 2/6/2020 | 77.53 | -0.12% | 46.01 | 0.04% | 54.41 | -0.15% | 97.99 | -0.18% | 54.68 | 0.31% | 60.51 | -0.28% | 68.84 | -0.28% | 99.90 | -0.11% | 69.30 | 0.00% | | | 3,345.78 | 0.33% |
| 2/7/2020 | 76.80 | -0.94% | 45.95 | -0.13% | 53.95 | -0.85% | 98.06 | 0.07% | 54.49 | -0.35% | 60.65 | 0.23% | 68.38 | -0.67% | 99.75 | -0.15% | 68.71 | -0.85% | | | 3,327.71 | -0.54% |
| 2/10/2020 | 77.13 | 0.43% | 46.13 | 0.39% | 54.22 | 0.50% | 98.81 | 0.76% | 54.45 | -0.07% | 61.04 | 0.64% | 68.44 | 0.09% | 100.14 | 0.39% | 69.06 | 0.51% | | | 3,352.09 | 0.73% |
| 2/11/2020 | 77.35 | 0.29% | 45.96 | -0.37% | 54.12 | -0.18% | 98.61 | -0.20% | 55.13 | 1.25% | 61.37 | 0.54% | 68.59 | 0.22% | 100.19 | 0.05% | 68.96 | -0.14% | | | 3,357.75 | 0.17% |
| 2/12/2020 | 77.46 | 0.14% | 45.83 | -0.28% | 54.13 | 0.02% | 98.65 | 0.04% | 55.11 | -0.04% | 60.98 | -0.64% | 68.62 | 0.04% | 100.75 | 0.56% | 69.03 | 0.10% | | | 3,379.45 | 0.65% |
| 2/13/2020 | 78.44 | 1.27% | 45.77 | -0.13% | 54.36 | 0.42% | 100.22 | 1.59% | 55.77 | 1.20% | 62.34 | 2.23% | 69.54 | 1.34% | 101.21 | 0.46% | 69.82 | 1.14% | | | 3,373.94 | -0.16% |
| 2/14/2020 | 78.92 | 0.61% | 46.12 | 0.76% | 54.78 | 0.77% | 100.43 | 0.21% | 55.78 | 0.02% | 61.80 | -0.87% | 69.02 | -0.75% | 101.87 | 0.65% | 70.26 | 0.63% | | | 3,380.16 | 0.18% |
| 2/18/2020 | 79.74 | 1.04% | 46.04 | -0.17% | 54.45 | -0.60% | 101.81 | 1.37% | 55.79 | 0.02% | 62.36 | 0.91% | 69.40 | 0.55% | 102.88 | 0.99% | 71.16 | 1.28% | | | 3,370.29 | -0.29% |
| 2/19/2020 | 80.22 | 0.60% | 45.20 | -1.82% | 56.09 | 3.01% | 101.54 | -0.27% | 55.05 | -1.33% | 62.21 | -0.24% | 68.61 | -1.14% | 102.41 | -0.46% | 70.79 | -0.52% | | | 3,386.15 | 0.47% |
| 2/20/2020 | 79.90 | -0.40% | 44.92 | -0.62% | 56.02 | -0.12% | 101.09 | -0.44% | 54.83 | -0.40% | 62.46 | 0.40% | 69.81 | 1.75% | 102.39 | -0.02% | 70.67 | -0.17% | | | 3,373.23 | -0.38% |
| 2/21/2020 | 79.01 | -1.11% | 45.03 | 0.24% | 55.41 | -1.09% | 103.60 | 2.48% | 54.51 | -0.58% | 62.37 | -0.14% | 68.99 | -1.17% | 102.50 | 0.11% | 70.82 | 0.21% | | | 3,337.75 | -1.05% |
| 2/24/2020 | 78.45 | -0.71% | 44.50 | -1.18% | 53.44 | -3.56% | 100.94 | -2.57% | 54.26 | -0.46% | 61.65 | -1.15% | 67.80 | -1.72% | 101.82 | -0.66% | 70.37 | -0.64% | | | 3,225.89 | -3.35% |
| 2/25/2020 | 77.43 | -1.30% | 43.85 | -1.46% | 52.10 | -2.51% | 98.40 | -2.52% | 53.10 | -2.14% | 60.81 | -1.36% | 66.86 | -1.39% | 100.41 | -1.38% | 68.84 | -2.17% | | | 3,128.21 | -3.03% |
| 2/26/2020 | 77.13 | -0.39% | 43.12 | -1.66% | 52.17 | 0.13% | 97.20 | -1.22% | 52.23 | -1.64% | 60.33 | -0.79% | 66.19 | -1.00% | 100.29 | -0.12% | 68.35 | -0.71% | | | 3,116.39 | -0.38% |
| 2/27/2020 | 74.50 | -3.41% | 40.49 | -6.10% | 50.27 | -3.64% | 93.61 | -3.69% | 49.55 | -5.13% | 57.65 | -4.44% | 62.88 | -5.00% | 95.56 | -4.72% | 64.85 | -5.12% | | | 2,978.76 | -4.42% |
| 2/28/2020 | 70.34 | -5.58% | 38.10 | -5.90% | 48.61 | -3.30% | 89.49 | -4.40% | 47.08 | -4.98% | 54.41 | -5.62% | 60.36 | -4.01% | 92.33 | -3.38% | 62.32 | -3.90% | | | 2,954.22 | -0.82% |
| 3/2/2020 | 74.33 | 5.67% | 39.48 | 3.62% | 50.00 | 2.86% | 94.91 | 6.06% | 49.54 | 5.23% | 57.34 | 5.39% | 63.93 | 5.91% | 97.69 | 5.81% | 65.87 | 5.70% | | | 3,090.23 | 4.60% |
| 3/3/2020 | 73.76 | -0.77% | 38.66 | -2.08% | 49.45 | -1.10% | 94.49 | -0.44% | 49.08 | -0.93% | 56.86 | -0.84% | 63.90 | -0.05% | 97.58 | -0.11% | 65.71 | -0.24% | | | 3,003.37 | -2.81% |
| 3/4/2020 | 77.90 | 5.61% | 40.04 | 3.57% | 51.36 | 3.86% | 100.26 | 6.11% | 52.09 | 6.13% | 59.58 | 4.78% | 67.80 | 6.10% | 104.21 | 6.79% | 69.20 | 5.31% | | | 3,130.12 | 4.22% |
| 3/5/2020 | 76.68 | -1.57% | 38.94 | -2.75% | 50.20 | -2.26% | 99.67 | -0.59% | 51.86 | -0.44% | 58.66 | -1.54% | 67.57 | -0.34% | 104.11 | -0.10% | 69.25 | 0.07% | | | 3,023.94 | -3.39% |
| 3/6/2020 | 76.91 | 0.30% | 37.75 | -3.06% | 50.80 | 1.20% | 99.31 | -0.36% | 51.83 | -0.06% | 58.33 | -0.56% | 66.87 | -1.04% | 104.72 | 0.59% | 70.15 | 1.30% | | | 2,972.37 | -1.71% |
| 3/9/2020 | 73.30 | -4.69% | 33.71 | -10.70% | 46.57 | -8.33% | 95.37 | -3.97% | 47.26 | -8.82% | 54.65 | -6.31% | 62.16 | -7.04% | 102.37 | -2.24% | 67.99 | -3.08% | | | 2,746.56 | -7.60% |
| 3/10/2020 | 75.00 | 2.32% | 35.30 | 4.72% | 47.40 | 1.78% | 96.19 | 0.86% | 48.73 | 3.11% | 55.64 | 1.81% | 62.02 | -0.23% | 102.05 | -0.31% | 68.49 | 0.74% | | | 2,882.23 | 4.94% |
| 3/11/2020 | 70.96 | -5.39% | 34.03 | -3.60% | 45.33 | -4.37% | 89.55 | -6.90% | 45.65 | -6.32% | 54.09 | -2.79% | 58.18 | -6.19% | 97.45 | -4.51% | 66.82 | -2.44% | | | 2,741.38 | -4.89% |
| 3/12/2020 | 61.71 | -13.04% | 32.11 | -5.64% | 38.15 | -15.84% | 80.10 | -10.55% | 39.50 | -13.47% | 45.38 | -16.10% | 52.19 | -10.30% | 91.64 | -5.96% | 61.29 | -8.28% | | | 2,480.64 | -9.51% |
| 3/13/2020 | 67.52 | 9.42% | 33.17 | 3.30% | 41.80 | 9.57% | 81.57 | 1.84% | 41.38 | 4.76% | 48.83 | 7.60% | 53.97 | 3.41% | 99.42 | 8.49% | 66.84 | 9.06% | | | 2,711.02 | 9.29% |
| 3/16/2020 | 56.98 | -15.61% | 30.62 | -7.69% | 33.13 | -20.74% | 68.11 | -16.50% | 33.79 | -18.34% | 41.59 | -14.83% | 47.62 | -11.77% | 92.68 | -6.78% | 58.36 | -12.69% | | | 2,386.13 | -11.98% |
| 3/17/2020 | 64.51 | 13.22% | 30.43 | -0.62% | 41.37 | 24.87% | 74.83 | 9.87% | 36.65 | 8.46% | 48.30 | 16.13% | 56.56 | 18.77% | 102.46 | 10.55% | 64.93 | 11.26% | | | 2,529.19 | 6.00% |
| 3/18/2020 | 53.53 | -17.02% | 27.74 | -8.84% | 40.32 | -2.54% | 65.57 | -12.37% | 31.13 | -15.06% | 49.08 | 1.61% | 55.92 | -1.13% | 104.53 | 2.02% | 61.37 | -5.48% | | | 2,398.10 | -5.18% |
| 3/19/2020 | 57.29 | 7.02% | 27.14 | -2.16% | 43.26 | 7.29% | 68.36 | 4.25% | 33.43 | 7.39% | 47.47 | -3.28% | 50.90 | -8.98% | 90.41 | -13.51% | 57.99 | -5.51% | | | 2,409.39 | 0.47% |
| 3/20/2020 | 48.25 | -15.78% | 25.71 | -5.27% | 36.14 | -16.46% | 65.55 | -4.11% | 29.93 | -10.47% | 40.28 | -15.15% | 46.36 | -8.92% | 74.09 | -18.05% | 50.63 | -12.69% | | | 2,304.92 | -4.34% |
| 3/23/2020 | 48.93 | 1.41% | 23.67 | -7.93% | 36.98 | 2.32% | 62.91 | -4.03% | 31.22 | 4.31% | 39.72 | -1.39% | 43.23 | -6.75% | 70.89 | -4.32% | 50.00 | -1.24% | | | 2,237.40 | -2.93% |
| 3/24/2020 | 52.62 | 7.54% | 27.03 | 14.20% | 40.82 | 10.38% | 71.04 | 12.92% | 33.78 | 8.20% | 43.32 | 9.06% | 49.04 | 13.44% | 80.21 | 13.15% | 54.05 | 8.10% | | | 2,447.33 | 9.38% |
| 3/25/2020 | 53.34 | 1.37% | 29.06 | 7.51% | 39.41 | -3.45% | 72.66 | 2.28% | 34.29 | 1.51% | 43.66 | 0.78% | 50.14 | 2.24% | 80.74 | 0.66% | 55.55 | 2.78% | | | 2,475.56 | 1.15% |
| 3/26/2020 | 59.10 | 10.80% | 31.37 | 7.95% | 44.09 | 11.88% | 79.34 | 9.19% | 38.79 | 13.12% | 48.02 | 9.99% | 55.14 | 9.97% | 86.77 | 7.47% | 57.91 | 4.25% | | | 2,630.07 | 6.24% |
| 3/27/2020 | 59.99 | 1.51% | 32.01 | 2.04% | 43.32 | -1.75% | 77.63 | -2.16% | 39.60 | 2.09% | 48.25 | 0.48% | 56.01 | 1.58% | 89.07 | 2.65% | 58.77 | 1.49% | | | 2,541.47 | -3.37% |
| 3/30/2020 | 61.56 | 2.62% | 31.90 | -0.34% | 46.17 | 6.58% | 78.36 | 0.94% | 39.42 | -0.45% | 51.23 | 6.18% | 57.99 | 3.54% | 91.89 | 3.17% | 62.56 | 6.45% | | | 2,626.65 | 3.35% |
| 3/31/2020 | 59.83 | -2.81% | 30.73 | -3.67% | 44.46 | -3.70% | 75.79 | -3.28% | 38.00 | -3.60% | 47.94 | -6.42% | 54.14 | -6.64% | 88.13 | -4.09% | 60.30 | -3.61% | | | 2,584.59 | -1.60% |
| 4/1/2020 | 55.71 | -6.89% | 29.08 | -5.37% | 42.14 | -5.22% | 70.84 | -6.53% | 36.20 | -4.74% | 47.17 | -1.61% | 50.14 | -7.39% | 83.52 | -5.23% | 58.08 | -3.68% | | | 2,470.50 | -4.41% |
| 4/2/2020 | 56.11 | 0.72% | 29.12 | 0.14% | 43.35 | 2.87% | 71.77 | 1.31% | 38.44 | 6.19% | 48.48 | 2.78% | 52.40 | 4.51% | 88.01 | 5.38% | 60.42 | 4.03% | | | 2,526.90 | 2.28% |
| 4/3/2020 | 52.84 | -5.83% | 26.58 | -8.72% | 42.86 | -1.13% | 68.19 | -4.99% | 38.10 | -0.88% | 46.31 | -4.48% | 50.27 | -4.06% | 85.25 | -3.14% | 57.86 | -4.24% | | | 2,488.65 | -1.51% |
| 4/6/2020 | 58.93 | 11.53% | 28.96 | 8.95% | 46.05 | 7.44% | 74.33 | 9.00% | 41.96 | 10.13% | 50.79 | 9.67% | 55.40 | 10.20% | 91.28 | 7.07% | 61.15 | 5.69% | | | 2,663.68 | 7.03% |
| 4/7/2020 | 57.70 | -2.09% | 29.79 | 2.87% | 43.71 | -5.08% | 73.60 | -0.98% | 42.19 | 0.55% | 49.05 | -3.43% | 55.12 | -0.51% | 87.76 | -3.86% | 59.23 | -3.14% | | | 2,659.41 | -0.16% |
| 4/8/2020 | 61.21 | 6.08% | 31.29 | 5.04% | 44.68 | 2.22% | 78.87 | 7.16% | 44.32 | 5.05% | 51.37 | 4.73% | 58.18 | 5.55% | 92.20 | 5.06% | 62.80 | 6.03% | | | 2,749.98 | 3.41% |
| 4/9/2020 | 64.60 | 5.54% | 32.52 | 3.93% | 47.55 | 6.42% | 82.23 | 4.26% | 46.58 | 5.10% | 52.52 | 2.24% | 60.33 | 3.70% | 98.22 | 6.53% | 66.27 | 5.53% | | | 2,789.82 | 1.45% |
| 4/13/2020 | 63.30 | -2.01% | 31.97 | -1.69% | 46.14 | -2.97% | 79.61 | -3.19% | 43.79 | -5.99% | 50.84 | -3.20% | 57.72 | -4.33% | 95.02 | -3.26% | 63.66 | -3.95% | | | 2,761.63 | -1.01% |
| 4/14/2020 | 64.39 | 1.72% | 32.93 | 3.00% | 46.86 | 1.56% | 81.83 | 2.79% | 45.02 | 2.81% | 51.17 | 0.65% | 59.00 | 2.22% | 99.33 | 4.54% | 66.25 | 4.08% | | | 2,846.06 | 3.06% |
| 4/15/2020 | 61.64 | -4.27% | 31.15 | -5.41% | 43.36 | -7.47% | 79.66 | -2.65% | 42.86 | -4.80% | 48.89 | -4.46% | 55.89 | -5.27% | 96.89 | -2.46% | 64.30 | -2.94% | | | 2,783.36 | -2.20% |
| 4/16/2020 | 60.93 | -1.15% | 30.73 | -1.35% | 44.30 | 2.17% | 79.01 | -0.82% | 42.66 | -0.47% | 49.33 | 0.90% | 55.32 | -1.02% | 98.96 | 2.14% | 65.25 | 1.48% | | | 2,799.55 | 0.58% |
| 4/17/2020 | 62.64 | 2.81% | 31.71 | 3.19% | 45.53 | 2.78% | 79.91 | 1.14% | 43.21 | 1.29% | 50.82 | 3.02% | 57.47 | 3.89% | 100.34 | 1.39% | 67.15 | 2.91% | | | 2,874.56 | 2.68% |
| 4/20/2020 | 58.30 | -6.93% | 30.25 | -4.60% | 43.93 | -3.51% | 76.60 | -4.14% | 40.63 | -5.97% | 47.95 | -5.65% | 55.53 | -3.38% | 95.88 | -4.44% | 64.35 | -4.17% | | | 2,823.16 | -1.79% |
| 4/21/2020 | 59.11 | 1.39% | 29.46 | -2.61% | 43.95 | 0.05% | 75.61 | -1.29% | 39.70 | -2.29% | 47.95 | 0.00% | 55.50 | -0.05% | 95.14 | -0.77% | 63.41 | -1.46% | | | 2,736.56 | -3.07% |
| 4/22/2020 | 59.19 | 0.14% | 30.69 | 4.18% | 43.71 | -0.55% | 77.58 | 2.61% | 41.11 | 3.55% | 49.59 | 3.42% | 57.05 | 2.79% | 96.40 | 1.32% | 65.32 | 3.01% | | | 2,799.31 | 2.29% |
| 4/23/2020 | 57.45 | -2.94% | 30.70 | 0.03% | 43.27 | -1.01% | 75.82 | -2.27% | 40.60 | -1.24% | 48.43 | -2.34% | 56.80 | -0.44% | 94.39 | -2.09% | 64.38 | -1.44% | | | 2,797.80 | -0.05% |
| 4/24/2020 | 56.80 | -1.13% | 31.27 | 1.86% | 43.28 | 0.02% | 77.14 | 1.74% | 41.32 | 1.77% | 46.41 | -4.17% | 57.73 | 1.64% | 93.77 | -0.66% | 64.57 | 0.30% | | | 2,836.74 | 1.39% |
| 4/27/2020 | 58.52 | 3.03% | 32.20 | 2.97% | 44.02 | 1.71% | 78.76 | 2.10% | 42.36 | 2.52% | 46.31 | -0.22% | 58.48 | 1.30% | 91.52 | -2.40% | 65.47 | 1.39% | | | 2,878.48 | 1.47% |
| 4/28/2020 | 60.75 | 3.81% | 32.43 | 0.71% | 45.08 | 2.41% | 79.99 | 1.56% | 42.67 | 0.73% | 47.41 | 2.38% | 58.06 | -0.72% | 94.73 | 3.51% | 66.17 | 1.07% | | | 2,863.39 | -0.52% |
| 4/29/2020 | 59.79 | -1.58% | 32.51 | 0.25% | 46.22 | 2.53% | 78.55 | -1.80% | 42.78 | 0.26% | 48.08 | 1.41% | 57.37 | -1.19% | 93.31 | -1.50% | 65.08 | -1.65% | | | 2,939.51 | 2.66% |
| 4/30/2020 | 57.69 | -3.51% | 31.52 | -3.05% | 44.38 | -3.98% | 76.99 | -1.99% | 40.49 | -5.35% | 46.79 | -2.68% | 56.73 | -1.12% | 90.55 | -2.96% | 63.56 | -2.34% | | | 2,912.43 | -0.92% |
| 5/1/2020 | 56.07 | -2.81% | 30.31 | -3.84% | 42.91 | -3.31% | 74.12 | -3.73% | 39.06 | -3.53% | 44.61 | -4.66% | 54.41 | -4.09% | 88.46 | -2.31% | 62.18 | -2.17% | | | 2,830.71 | -2.81% |
| 5/4/2020 | 56.29 | 0.39% | 30.46 | 0.49% | 43.44 | 1.24% | 73.65 | -0.63% | 38.81 | -0.64% | 45.58 | 2.17% | 54.92 | 0.94% | 88.96 | 0.57% | 62.39 | 0.34% | | | 2,842.74 | 0.43% |
| 5/5/2020 | 57.16 | 1.55% | 30.32 | -0.46% | 43.15 | -0.67% | 74.64 | 1.34% | 38.89 | 0.21% | 45.52 | -0.13% | 55.63 | 1.29% | 89.58 | 0.70% | 63.28 | 1.42% | | | 2,868.44 | 0.90% |
| 5/6/2020 | 54.19 | -5.20% | 29.25 | -3.53% | 41.26 | -4.38% | 72.01 | -3.52% | 37.20 | -4.35% | 43.33 | -4.81% | 53.64 | -3.58% | 84.94 | -5.18% | 61.22 | -3.25% | | | 2,848.42 | -0.70% |
| 5/7/2020 | 55.84 | 3.04% | 29.29 | 0.14% | 41.63 | 0.90% | 71.76 | -0.35% | 38.24 | 2.80% | 44.09 | 1.75% | 54.23 | 1.10% | 85.13 | 0.22% | 59.96 | -2.06% | | | 2,881.19 | 1.15% |
| 5/8/2020 | 58.03 | 3.92% | 31.05 | 6.01% | 43.46 | 4.40% | 73.87 | 2.94% | 39.35 | 2.90% | 45.31 | 2.77% | 55.41 | 2.18% | 85.68 | 0.65% | 60.31 | 0.58% | | | 2,929.80 | 1.69% |
| 5/11/2020 | 57.46 | -0.98% | 30.53 | -1.67% | 42.28 | -2.72% | 73.65 | -0.30% | 37.99 | -3.46% | 45.01 | -0.66% | 55.81 | 0.72% | 85.32 | -0.42% | 60.13 | -0.30% | | | 2,930.32 | 0.02% |
| 5/12/2020 | 56.00 | -2.54% | 29.94 | -1.93% | 40.57 | -4.04% | 72.48 | -1.59% | 36.81 | -3.11% | 42.85 | -4.80% | 55.52 | -0.52% | 85.01 | -0.36% | 58.79 | -2.23% | | | 2,870.12 | -2.05% |
| 5/13/2020 | 54.96 | -1.86% | 28.86 | -3.61% | 39.35 | -3.01% | 72.46 | -0.03% | 35.77 | -2.83% | 41.43 | -3.31% | 53.79 | -3.12% | 84.76 | -0.29% | 58.06 | -1.24% | | | 2,820.00 | -1.75% |
| 5/14/2020 | 54.99 | 0.05% | 29.34 | 1.66% | 38.54 | -2.06% | 72.02 | -0.61% | 36.04 | 0.75% | 41.22 | -0.51% | 54.75 | 1.78% | 84.71 | -0.06% | 58.20 | 0.24% | | | 2,852.50 | 1.15% |
| 5/15/2020 | 54.25 | -1.35% | 28.53 | -2.76% | 38.71 | 0.44% | 71.42 | -0.83% | 37.21 | 3.25% | 40.77 | -1.09% | 52.54 | -4.04% | 84.80 | 0.11% | 57.89 | -0.53% | | | 2,863.70 | 0.39% |
| 5/18/2020 | 57.71 | 6.38% | 30.79 | 7.92% | 41.24 | 6.54% | 74.86 | 4.82% | 40.00 | 7.50% | 43.22 | 6.01% | 54.42 | 3.58% | 87.62 | 3.33% | 60.13 | 3.87% | | | 2,953.91 | 3.15% |
| 5/19/2020 | 56.62 | -1.89% | 30.15 | -2.08% | 39.56 | -4.07% | 72.59 | -3.03% | 39.77 | -0.57% | 41.99 | -2.85% | 53.57 | -1.56% | 86.69 | -1.06% | 59.70 | -0.72% | | | 2,922.94 | -1.05% |
| 5/20/2020 | 57.80 | 2.08% | 31.12 | 3.22% | 40.87 | 3.31% | 72.77 | 0.25% | 39.70 | -0.18% | 42.81 | 1.95% | 54.83 | 2.35% | 87.30 | 0.70% | 60.25 | 0.92% | | | 2,971.61 | 1.67% |
| 5/21/2020 | 57.56 | -0.42% | 30.68 | -1.41% | 40.90 | 0.07% | 72.28 | -0.67% | 38.62 | -2.72% | 42.87 | 0.14% | 53.83 | -1.82% | 86.68 | -0.71% | 60.15 | -0.17% | | | 2,948.51 | -0.78% |
| 5/22/2020 | 57.84 | 0.49% | 30.80 | 0.39% | 41.41 | 1.25% | 72.66 | 0.53% | 38.52 | -0.26% | 42.95 | 0.19% | 54.58 | 1.39% | 86.14 | -0.62% | 60.37 | 0.37% | | | 2,955.45 | 0.24% |
| 5/26/2020 | 59.12 | 2.21% | 31.83 | 3.34% | 42.43 | 2.46% | 74.34 | 2.31% | 39.01 | 1.27% | 44.16 | 2.82% | 54.66 | 0.15% | 85.69 | -0.52% | 61.06 | 1.14% | | | 2,991.77 | 1.23% |
| 5/27/2020 | 60.12 | 1.69% | 31.42 | -1.29% | 42.58 | 0.35% | 75.50 | 1.56% | 39.24 | 0.59% | 44.76 | 1.36% | 55.01 | 0.64% | 85.90 | 0.25% | 61.73 | 1.10% | | | 3,036.13 | 1.48% |
| 5/28/2020 | 60.08 | -0.07% | 31.89 | 1.50% | 43.12 | 1.27% | 76.85 | 1.79% | 40.32 | 2.75% | 46.07 | 2.93% | 56.91 | 3.45% | 88.97 | 3.57% | 64.01 | 3.69% | | | 3,029.73 | -0.21% |
| 5/29/2020 | 60.12 | 0.07% | 31.32 | -1.79% | 42.91 | -0.49% | 77.90 | 1.37% | 40.82 | 1.24% | 47.11 | 2.26% | 57.07 | 0.28% | 91.73 | 3.10% | 65.03 | 1.59% | | | 3,044.31 | 0.48% |
| 6/1/2020 | 60.45 | 0.55% | 32.14 | 2.62% | 42.00 | -2.12% | 77.58 | -0.41% | 40.44 | -0.93% | 46.52 | -1.25% | 57.70 | 1.10% | 93.13 | 1.53% | 65.75 | 1.11% | | | 3,055.73 | 0.38% |
| 6/2/2020 | 60.21 | -0.40% | 32.18 | 0.12% | 42.05 | 0.12% | 78.16 | 0.75% | 40.74 | 0.74% | 47.49 | 2.09% | 58.00 | 0.52% | 93.97 | 0.90% | 66.07 | 0.49% | | | 3,080.82 | 0.82% |
| 6/3/2020 | 62.10 | 3.14% | 33.00 | 2.55% | 43.12 | 2.54% | 78.97 | 1.04% | 41.38 | 1.57% | 48.18 | 1.45% | 58.71 | 1.22% | 93.96 | -0.01% | 66.82 | 1.14% | | | 3,122.87 | 1.36% |
| 6/4/2020 | 60.76 | -2.16% | 32.66 | -1.03% | 41.84 | -2.97% | 77.83 | -1.44% | 40.64 | -1.79% | 47.00 | -2.45% | 57.95 | -1.29% | 92.57 | -1.48% | 65.03 | -2.68% | | | 3,112.35 | -0.34% |
| 6/5/2020 | 62.81 | 3.37% | 33.60 | 2.88% | 43.55 | 4.09% | 79.38 | 1.99% | 42.50 | 4.58% | 47.56 | 1.19% | 58.45 | 0.86% | 92.85 | 0.30% | 65.26 | 0.35% | | | 3,193.93 | 2.62% |
| 6/8/2020 | 63.24 | 0.68% | 34.80 | 3.57% | 44.20 | 1.49% | 82.04 | 3.35% | 43.15 | 1.53% | 48.28 | 1.51% | 60.27 | 3.11% | 95.28 | 2.62% | 66.95 | 2.59% | | | 3,232.39 | 1.20% |
| 6/9/2020 | 62.22 | -1.61% | 33.53 | -3.65% | 42.77 | -3.24% | 80.11 | -2.35% | 41.90 | -2.90% | 47.58 | -1.45% | 59.36 | -1.51% | 93.44 | -1.93% | 66.37 | -0.87% | | | 3,207.18 | -0.78% |
| 6/10/2020 | 60.70 | -2.44% | 32.73 | -2.39% | 42.86 | 0.21% | 78.13 | -2.47% | 40.74 | -2.77% | 46.70 | -1.85% | 59.20 | -0.27% | 93.71 | 0.29% | 66.93 | 0.84% | | | 3,190.14 | -0.53% |
| 6/11/2020 | 56.51 | -6.90% | 30.41 | -7.09% | 39.62 | -7.56% | 74.70 | -4.39% | 38.64 | -5.15% | 44.66 | -4.37% | 56.09 | -5.25% | 91.33 | -2.54% | 65.08 | -2.76% | | | 3,002.10 | -5.89% |
| 6/12/2020 | 55.58 | -1.65% | 30.86 | 1.48% | 39.90 | 0.71% | 75.60 | 1.20% | 38.73 | 0.23% | 44.63 | -0.07% | 56.17 | 0.14% | 90.31 | -1.12% | 63.65 | -2.20% | | | 3,041.31 | 1.31% |
| 6/15/2020 | 56.48 | 1.62% | 31.22 | 1.17% | 40.14 | 0.60% | 77.09 | 1.97% | 38.99 | 0.67% | 45.13 | 1.12% | 56.42 | 0.45% | 90.47 | 0.18% | 63.51 | -0.22% | | | 3,066.59 | 0.83% |
| 6/16/2020 | 56.82 | 0.60% | 31.29 | 0.22% | 40.12 | -0.05% | 77.23 | 0.18% | 39.30 | 0.80% | 45.07 | -0.13% | 56.22 | -0.35% | 90.82 | 0.39% | 63.74 | 0.36% | | | 3,124.74 | 1.90% |
| 6/17/2020 | 55.90 | -1.62% | 30.96 | -1.05% | 39.12 | -2.49% | 76.25 | -1.27% | 38.61 | -1.76% | 44.52 | -1.22% | 56.04 | -0.32% | 90.42 | -0.44% | 63.89 | 0.24% | | | 3,113.49 | -0.36% |
| 6/18/2020 | 55.71 | -0.34% | 30.98 | 0.06% | 38.99 | -0.33% | 76.65 | 0.52% | 38.52 | -0.23% | 44.25 | -0.61% | 56.11 | 0.12% | 89.86 | -0.62% | 64.51 | 0.97% | | | 3,115.34 | 0.06% |
| 6/19/2020 | 54.56 | -2.06% | 30.54 | -1.42% | 38.18 | -2.08% | 73.50 | -4.11% | 37.50 | -2.65% | 43.00 | -2.82% | 53.61 | -4.46% | 88.07 | -1.99% | 64.01 | -0.78% | | | 3,097.74 | -0.57% |
| 6/22/2020 | 54.60 | 0.07% | 30.84 | 0.98% | 39.08 | 2.34% | 73.28 | -0.30% | 38.19 | 1.84% | 43.03 | 0.07% | 54.67 | 1.98% | 87.85 | -0.25% | 65.15 | 1.78% | | | 3,117.86 | 0.65% |
| 6/23/2020 | 54.14 | -0.84% | 30.58 | -0.84% | 38.80 | -0.70% | 72.24 | -1.42% | 38.34 | 0.39% | 43.22 | 0.44% | 53.27 | -2.56% | 87.09 | -0.87% | 64.19 | -1.47% | | | 3,131.29 | 0.43% |
| 6/24/2020 | 52.86 | -2.36% | 30.34 | -0.78% | 38.07 | -1.88% | 71.62 | -0.86% | 37.95 | -1.02% | 41.79 | -3.31% | 52.38 | -1.67% | 86.79 | -0.34% | 63.68 | -0.79% | | | 3,050.33 | -2.59% |
| 6/25/2020 | 52.24 | -1.17% | 30.06 | -0.92% | 37.82 | -0.66% | 71.36 | -0.36% | 37.97 | 0.05% | 41.24 | -1.32% | 51.25 | -2.16% | 85.21 | -1.82% | 62.90 | -1.22% | | | 3,083.76 | 1.10% |
| 6/26/2020 | 52.14 | -0.19% | 29.37 | -2.30% | 36.91 | -2.41% | 71.05 | -0.43% | 37.10 | -2.29% | 40.28 | -2.33% | 50.92 | -0.64% | 85.54 | 0.39% | 62.31 | -0.94% | | | 3,009.05 | -2.42% |
| 6/29/2020 | 54.10 | 3.76% | 30.40 | 3.51% | 38.57 | 4.50% | 72.96 | 2.69% | 38.43 | 3.58% | 41.74 | 3.62% | 51.56 | 1.26% | 86.97 | 1.67% | 62.46 | 0.24% | | | 3,053.24 | 1.47% |
| 6/30/2020 | 54.52 | 0.78% | 30.36 | -0.13% | 38.79 | 0.57% | 73.29 | 0.45% | 38.44 | 0.03% | 41.81 | 0.17% | 51.85 | 0.56% | 87.65 | 0.78% | 62.50 | 0.06% | | | 3,100.29 | 1.54% |
| 7/1/2020 | 55.41 | 1.63% | 30.52 | 0.53% | 39.22 | 1.11% | 75.39 | 2.87% | 39.33 | 2.32% | 42.53 | 1.72% | 52.87 | 1.97% | 89.33 | 1.92% | 64.19 | 2.70% | | | 3,115.86 | 0.50% |
| 7/2/2020 | 55.31 | -0.18% | 30.63 | 0.36% | 39.26 | 0.10% | 76.03 | 0.85% | 39.28 | -0.13% | 42.71 | 0.42% | 52.79 | -0.15% | 90.17 | 0.94% | 64.10 | -0.13% | | | 3,130.01 | 0.45% |
| 7/6/2020 | 54.76 | -0.99% | 30.52 | -0.36% | 38.66 | -1.53% | 76.80 | 1.01% | 39.28 | 0.00% | 41.94 | -1.80% | 52.61 | -0.34% | 89.94 | -0.26% | 63.58 | -0.81% | | | 3,179.72 | 1.59% |
| 7/7/2020 | 53.30 | -2.67% | 30.82 | 0.98% | 38.12 | -1.40% | 76.00 | -1.04% | 38.41 | -2.21% | 41.15 | -1.88% | 52.72 | 0.21% | 88.70 | -1.38% | 63.60 | 0.03% | | | 3,145.32 | -1.08% |
| 7/8/2020 | 53.57 | 0.51% | 30.79 | -0.10% | 38.05 | -0.18% | 76.72 | 0.95% | 38.85 | 1.15% | 41.42 | 0.66% | 53.06 | 0.64% | 88.74 | 0.05% | 63.77 | 0.27% | | | 3,169.94 | 0.78% |
| 7/9/2020 | 52.42 | -2.15% | 29.97 | -2.66% | 37.39 | -1.73% | 76.25 | -0.61% | 37.87 | -2.52% | 40.52 | -2.17% | 51.94 | -2.11% | 87.47 | -1.43% | 63.24 | -0.83% | | | 3,152.05 | -0.56% |
| 7/10/2020 | 53.32 | 1.72% | 30.96 | 3.30% | 38.30 | 2.43% | 78.26 | 2.64% | 38.87 | 2.64% | 42.11 | 3.92% | 53.23 | 2.48% | 88.05 | 0.66% | 63.77 | 0.84% | | | 3,185.04 | 1.05% |
| Price 1/31/2020 | 76.97 | | 45.85 | | 53.56 | | 97.69 | | 54.23 | | 61.50 | | 70.40 | | 99.89 | | 69.19 | | | | 3,225.52 | |
| Price 7/10/2020 | 53.32 | | 30.96 | | 38.30 | | 78.26 | | 38.87 | | 42.11 | | 53.23 | | 88.05 | | 63.77 | | | | 3,185.04 | |
| Price Change (1) | -30.73% | | -32.48% | | -28.49% | | -19.89% | | -28.32% | | -31.53% | | -24.39% | | -11.85% | | -7.83% | | **-20.64%** | | **-1.25%** | |
| Standard Deviation of Returns | | 4.59% | | 3.79% | | 5.10% | | 3.87% | | 4.48% | | 4.30% | | 4.18% | | 3.84% | | 3.44% | | **4.04%** | | 3.08% |
| Annual Volatility (2) | | 72.86% | | 60.24% | | 80.88% | | 61.39% | | 71.15% | | 68.29% | | 66.31% | | 60.92% | | 54.67% | | **64.20%** | | 48.84% |

Bloomberg and Value Line Beta Coefficients DEC Direct (6/28/2019)

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.461 | 0.650 |
| Alliant Energy Corporation | LNT | 0.537 | 0.600 |
| Ameren Corporation | AEE | 0.465 | 0.600 |
| American Electric Power Company, Inc. | AEP | 0.511 | 0.550 |
| Avangrid, Inc. | AGR | 0.491 | 0.400 |
| CMS Energy Corporation | CMS | 0.479 | 0.550 |
| DTE Energy Company | DTE | 0.505 | 0.550 |
| Evergy, Inc | EVRG | 0.440 | 0.529 |
| Hawaiian Electric Industries, Inc. | HE | 0.488 | 0.600 |
| NextEra Energy, Inc. | NEE | 0.553 | 0.600 |
| NorthWestern Corporation | NWE | 0.494 | 0.600 |
| OGE Energy Corp. | OGE | 0.568 | 0.800 |
| Otter Tail Corporation | OTTR | 0.558 | 0.700 |
| Pinnacle West Capital Corporation | PNW | 0.447 | 0.550 |
| PNM Resources, Inc. | PNM | 0.521 | 0.650 |
| Portland General Electric Company | POR | 0.481 | 0.600 |
| Southern Company | SO | 0.479 | 0.500 |
| WEC Energy Group, Inc. | WEC | 0.483 | 0.500 |
| Xcel Energy Inc. | XEL | 0.497 | 0.500 |
| | | | |
| Mean | | 0.498 | 0.580 |

Notes:

[1] Source: Bloomberg Professional

[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the Beta coefficient for Evergy has been manually calculated according to Value Line's methodology.

Bloomberg and Value Line Beta Coefficients DEP Direct (8/16/2019)

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.480 | 0.650 |
| Alliant Energy Corporation | LNT | 0.530 | 0.600 |
| Ameren Corporation | AEE | 0.475 | 0.600 |
| American Electric Power Company, Inc. | AEP | 0.514 | 0.550 |
| Avangrid, Inc. | AGR | 0.478 | 0.400 |
| CMS Energy Corporation | CMS | 0.481 | 0.550 |
| DTE Energy Company | DTE | 0.511 | 0.550 |
| Evergy, Inc | EVRG | 0.450 | 0.521 |
| Hawaiian Electric Industries, Inc. | HE | 0.495 | 0.550 |
| NextEra Energy, Inc. | NEE | 0.544 | 0.550 |
| NorthWestern Corporation | NWE | 0.504 | 0.600 |
| OGE Energy Corp. | OGE | 0.557 | 0.800 |
| Otter Tail Corporation | OTTR | 0.563 | 0.700 |
| Pinnacle West Capital Corporation | PNW | 0.441 | 0.550 |
| PNM Resources, Inc. | PNM | 0.529 | 0.600 |
| Portland General Electric Company | POR | 0.488 | 0.600 |
| Southern Company | SO | 0.464 | 0.500 |
| WEC Energy Group, Inc. | WEC | 0.479 | 0.500 |
| Xcel Energy Inc. | XEL | 0.502 | 0.500 |
| Mean | | 0.499 | 0.572 |

Notes:

[1] Source: Bloomberg Professional

[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the Beta coefficient for Evergy has been manually calculated according to Value Line's methodology.

Bloomberg and Value Line Beta Coefficients DEC Rebuttal (1/31/2020)

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.484 | 0.650 |
| Alliant Energy Corporation | LNT | 0.537 | 0.600 |
| Ameren Corporation | AEE | 0.486 | 0.550 |
| American Electric Power Company, Inc. | AEP | 0.538 | 0.550 |
| Avangrid, Inc. | AGR | 0.508 | 0.400 |
| Avista | AVA | 0.492 | 0.600 |
| CMS Energy Corporation | CMS | 0.486 | 0.500 |
| DTE Energy Company | DTE | 0.528 | 0.550 |
| Evergy, Inc | EVRG | 0.437 | 0.511 |
| Hawaiian Electric Industries, Inc. | HE | 0.511 | 0.550 |
| NextEra Energy, Inc. | NEE | 0.523 | 0.550 |
| NorthWestern Corporation | NWE | 0.528 | 0.600 |
| OGE Energy Corp. | OGE | 0.583 | 0.750 |
| Otter Tail Corporation | OTTR | 0.631 | 0.700 |
| Pinnacle West Capital Corporation | PNW | 0.426 | 0.500 |
| PNM Resources, Inc. | PNM | 0.528 | 0.600 |
| Portland General Electric Company | POR | 0.524 | 0.550 |
| Southern Company | SO | 0.512 | 0.500 |
| WEC Energy Group, Inc. | WEC | 0.471 | 0.500 |
| Xcel Energy Inc. | XEL | 0.517 | 0.500 |
| | | | |
| Mean | | 0.513 | 0.561 |

Notes:

[1] Source: Bloomberg Professional

[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the Beta coefficient for Evergy has been manually calculated according to Value Line's methodology.

Bloomberg and Value Line Beta Coefficients DEP Rebuttal (4/17/2020)

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.939 | 0.600 |
| Alliant Energy Corporation | LNT | 1.003 | 0.550 |
| Ameren Corporation | AEE | 0.922 | 0.500 |
| American Electric Power Company, Inc. | AEP | 0.983 | 0.500 |
| Avangrid, Inc. | AGR | 0.755 | 0.400 |
| Avista | AVA | 0.927 | 0.600 |
| CMS Energy Corporation | CMS | 0.940 | 0.500 |
| DTE Energy Company | DTE | 1.097 | 0.500 |
| Evergy, Inc | EVRG | 1.043 | 0.655 |
| Hawaiian Electric Industries, Inc. | HE | 0.768 | 0.550 |
| NextEra Energy, Inc. | NEE | 0.912 | 0.500 |
| NorthWestern Corporation | NWE | 1.184 | 0.600 |
| OGE Energy Corp. | OGE | 1.163 | 0.700 |
| Otter Tail Corporation | OTTR | 0.973 | 0.700 |
| Pinnacle West Capital Corporation | PNW | 1.051 | 0.500 |
| PNM Resources, Inc. | PNM | 1.269 | 0.600 |
| Portland General Electric Company | POR | 0.986 | 0.550 |
| Southern Company | SO | 1.050 | 0.500 |
| WEC Energy Group, Inc. | WEC | 0.978 | 0.500 |
| Xcel Energy Inc. | XEL | 0.958 | 0.450 |
| | | | |
| Mean | | 0.995 | 0.548 |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the Beta coefficient for Evergy has been manually calculated according to Value Line's methodology using data as of March 13, 2020, the date of Value Line's report for Evergy.

Bloomberg and Value Line Beta Coefficients DEC/DEP Supplemental Rebuttal (6/30/2020)

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.981 | 0.850 |
| Alliant Energy Corporation | LNT | 1.005 | 0.800 |
| Ameren Corporation | AEE | 0.921 | 0.800 |
| American Electric Power Company, Inc. | AEP | 0.969 | 0.750 |
| Avangrid, Inc. | AGR | 0.783 | 0.800 |
| Avista Corporation | AVA | 0.934 | 0.600 |
| CMS Energy Corporation | CMS | 0.938 | 0.800 |
| DTE Energy Company | DTE | 1.103 | 0.900 |
| Evergy, Inc | EVRG | 1.042 | 1.050 |
| Hawaiian Electric Industries, Inc. | HE | 0.773 | 0.550 |
| NextEra Energy, Inc. | NEE | 0.908 | 0.850 |
| NorthWestern Corporation | NWE | 1.212 | 0.550 |
| OGE Energy Corp. | OGE | 1.179 | 1.050 |
| Otter Tail Corporation | OTTR | 0.983 | 0.850 |
| Pinnacle West Capital Corporation | PNW | 1.041 | 0.450 |
| PNM Resources, Inc. | PNM | 1.261 | 0.500 |
| Portland General Electric Company | POR | 1.015 | 0.550 |
| Southern Company | SO | 1.036 | 0.900 |
| WEC Energy Group, Inc. | WEC | 0.969 | 0.800 |
| Xcel Energy Inc. | XEL | 0.954 | 0.450 |
| Mean | | 1.000 | 0.743 |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line.

**CERTIFICATE OF SERVICE**

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-7, SUB 1214

I hereby certify that a copy of the foregoing **SUPPLEMENTAL REBUTTAL TESTIMONY AND EXHIBITS OF DYLAN W. D'ASCENDIS FOR DUKE ENERGY PROGRESS, LLC AND DUKE ENERGY CAROLINAS, LLC** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 20th day of July 2020.

*/s/ Kiran H. Mehta*
Kiran H. Mehta
Troutman Pepper Hamilton Sanders LLP
301 S. College Street, Suite 3400
Charlotte, North Carolina 28202
Telephone: 704.998.4072
kiran.mehta@troutman.com

*Resume of:*
**Dylan W. D'Ascendis, CRRA, CVA**
**Director**

## Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). He has served as a consultant for investor-owned and municipal utilities and authorities for 11 years. Dylan has extensive experience in rate of return analyses, class cost of service, rate design, and valuation for regulated public utilities. He has testified as an expert witness in the subjects of rate of return, cost of service, rate design, and valuation before 19 regulatory commissions in the U.S., one Canadian province, and an American Arbitration Association panel.

He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured.

## Areas of Specialization

- Regulation and Rates
- Utilities
- Mutual Fund Benchmarking
- Capital Market Risk
- Financial Modeling
- Valuation
- Regulatory Strategy
- Rate Case Support
- Rate of Return
- Cost of Service
- Rate Design

## Recent Expert Testimony Submission/Appearances

| ***Jurisdiction*** | ***Topic*** |
|---|---|
| Massachusetts Department of Public Utilities | Rate of Return |
| New Jersey Board of Public Utilities | Rate of Return |
| Hawaii Public Utilities Commission | Cost of Service, Rate Design |
| South Carolina Public Service Commission | Return on Common Equity |
| American Arbitration Association | Valuation |

## Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

## Recent Publications and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020.
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319.
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA.
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013.
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN.

*Testimony Listing of:*
**Dylan W. D'Ascendis, CRRA, CVA**
**Director**

| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| **Regulatory Commission of Alaska** | | | | |
| Alaska Power Company | 07/16 | Alaska Power Company | Docket No. TA857-2 | Rate of Return |
| **Alberta Utilities Commission** | | | | |
| AltaLink, L.P., and EPCOR Distribution & Transmission, Inc. | 01/20 | AltaLink, L.P., and EPCOR Distribution & Transmission, Inc. | 2021Generic Cost of Capital, Proceeding ID. 24110 | Rate of Return |
| **Arizona Corporation Commission** | | | | |
| Arizona Water Company | 12/19 | Arizona Water Company – Western Group | Docket No. W01445A-19-0278 | Rate of Return |
| Arizona Water Company | 08/18 | Arizona Water Company – Northern Group | Docket No. W01445A-18-0164 | Rate of Return |
| **Colorado Public Utilities Commission** | | | | |
| Summit Utilities, Inc. | 04/18 | Colorado Natural Gas Company | Docket No. 18AL-0305G | Return on Equity |
| Atmos Energy Corporation | 06/17 | Atmos Energy Corporation | Docket No. 17AL-0429G | Return on Equity |
| **Delaware Public Service Commission** | | | | |
| Tidewater Utilities, Inc. | 11/13 | Tidewater Utilities, Inc. | Docket No. 13-466 | Capital Structure |
| **Hawaii Public Utilities Commission** | | | | |
| Lanai Water Company, Inc. | 12/19 | Lanai Water Company, Inc. | Docket No. 2019-0386 | Cost of Service / Rate Design |
| Manele Water Resources, LLC | 8/19 | Manele Water Resources, LLC | Docket No. 2019-0311 | Cost of Service / Rate Design |
| Kaupulehu Water Company | 02/18 | Kaupulehu Water Company | Docket No. 2016-0363 | Rate of Return |
| Aqua Engineers, LLC | 05/17 | Puhi Sewer & Water Company | Docket No. 2017-0118 | Cost of Service / Rate Design |
| Hawaii Resources, Inc. | 09/16 | Laie Water Company | Docket No. 2016-0229 | Cost of Service / Rate Design |
| **Illinois Commerce Commission** | | | | |
| Utility Services of Illinois, Inc. | 11/17 | Utility Services of Illinois, Inc. | Docket No. 17-1106 | Cost of Service / Rate Design |
| Aqua Illinois, Inc. | 04/17 | Aqua Illinois, Inc. | Docket No. 17-0259 | Rate of Return |
| Utility Services of Illinois, Inc. | 04/15 | Utility Services of Illinois, Inc. | Docket No. 14-0741 | Rate of Return |
| **Indiana Utility Regulatory Commission** | | | | |
| Aqua Indiana, Inc. | 03/16 | Aqua Indiana, Inc. Aboite Wastewater Division | Docket No. 44752 | Rate of Return |
| Twin Lakes, Utilities, Inc. | 08/13 | Twin Lakes, Utilities, Inc. | Docket No. 44388 | Rate of Return |
| **Kansas Corporation Commission** | | | | |
| Atmos Energy | 07/19 | Atmos Energy | 19-ATMG-525-RTS | Rate of Return |
| **Louisiana Public Service Commission** | | | | |
| Atmos Energy | 04/2020 | Atmos Energy | Docket No. U-35535 | Rate of Return |

scottmadden MANAGEMENT CONSULTANTS

*Testimony Listing of:*

**Dylan W. D'Ascendis, CRRA, CVA**
**Director**

| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| Louisiana Water Service, Inc. | 06/13 | Louisiana Water Service, Inc. | Docket No. U-32848 | Rate of Return |
| **Maryland Public Service Commission** | | | | |
| FirstEnergy, Inc. | 08/18 | Potomac Edison Company | Case No. 9490 | Rate of Return |
| **Massachusetts Department of Public Utilities** | | | | |
| Unitil Corporation | 12/19 | Fitchburg Gas & Electric Co. (Elec.) | D.P.U. 19-130 | Rate of Return |
| Unitil Corporation | 12/19 | Fitchburg Gas & Electric Co. (Gas) | D.P.U. 19-131 | Rate of Return |
| Liberty Utilities | 07/15 | Liberty Utilities d/b/a New England Natural Gas Company | Docket No. 15-75 | Rate of Return |
| **Mississippi Public Service Commission** | | | | |
| Atmos Energy | 03/19 | Atmos Energy | Docket No. 2015-UN-049 | Capital Structure |
| Atmos Energy | 07/18 | Atmos Energy | Docket No. 2015-UN-049 | Capital Structure |
| **Missouri Public Service Commission** | | | | |
| Indian Hills Utility Operating Company, Inc. | 10/17 | Indian Hills Utility Operating Company, Inc. | Case No. SR-2017-0259 | Rate of Return |
| Raccoon Creek Utility Operating Company, Inc. | 09/16 | Raccoon Creek Utility Operating Company, Inc. | Docket No. SR-2016-0202 | Rate of Return |
| **New Jersey Board of Public Utilities** | | | | |
| FirstEnergy | 02/2020 | Jersey Central Power & Light Co. | Docket No. ER20020146 | Rate of Return |
| Aqua New Jersey, Inc. | 12/18 | Aqua New Jersey, Inc. | Docket No. WR18121351 | Rate of Return |
| Middlesex Water Company | 10/17 | Middlesex Water Company | Docket No. WR17101049 | Rate of Return |
| Middlesex Water Company | 03/15 | Middlesex Water Company | Docket No. WR15030391 | Rate of Return |
| The Atlantic City Sewerage Company | 10/14 | The Atlantic City Sewerage Company | Docket No. WR14101263 | Cost of Service / Rate Design |
| Middlesex Water Company | 11/13 | Middlesex Water Company | Docket No. WR1311059 | Capital Structure |
| **North Carolina Utilities Commission** | | | | |
| Aqua North Carolina, Inc. | 12/19 | Aqua North Carolina, Inc. | Docket No. W-218 Sub 526 | Rate of Return |
| Carolina Water Service, Inc. | 06/19 | Carolina Water Service, Inc. | Docket No. W-354 Sub 364 | Rate of Return |
| Carolina Water Service, Inc. | 09/18 | Carolina Water Service, Inc. | Docket No. W-354 Sub 360 | Rate of Return |
| Aqua North Carolina, Inc. | 07/18 | Aqua North Carolina, Inc. | Docket No. W-218 Sub 497 | Rate of Return |
| **Public Utilities Commission of Ohio** | | | | |
| Aqua Ohio, Inc. | 05/16 | Aqua Ohio, Inc. | Docket No. 16-0907-WW-AIR | Rate of Return |
| **Pennsylvania Public Utility Commission** | | | | |
| Valley Energy, Inc. | 07/19 | C&T Enterprises | Docket No. R-2019-3008209 | Rate of Return |

*Testimony Listing of:*
**Dylan W. D'Ascendis, CRRA, CVA**
**Director**

scottmadden MANAGEMENT CONSULTANTS

| SPONSOR | DATE | CASE/APPLICANT | DOCKET NO. | SUBJECT |
|---|---|---|---|---|
| Wellsboro Electric Company | 07/19 | C&T Enterprises | Docket No. R-2019-3008208 | Rate of Return |
| Citizens' Electric Company of Lewisburg | 07/19 | C&T Enterprises | Docket No. R-2019-3008212 | Rate of Return |
| Steelton Borough Authority | 01/19 | Steelton Borough Authority | Docket No. A-2019-3006880 | Valuation |
| Mahoning Township, PA | 08/18 | Mahoning Township, PA | Docket No. A-2018-3003519 | Valuation |
| SUEZ Water Pennsylvania Inc. | 04/18 | SUEZ Water Pennsylvania Inc. | Docket No. R-2018-000834 | Rate of Return |
| Columbia Water Company | 09/17 | Columbia Water Company | Docket No. R-2017-2598203 | Rate of Return |
| Veolia Energy Philadelphia, Inc. | 06/17 | Veolia Energy Philadelphia, Inc. | Docket No. R-2017-2593142 | Rate of Return |
| Emporium Water Company | 07/14 | Emporium Water Company | Docket No. R-2014-2402324 | Rate of Return |
| Columbia Water Company | 07/13 | Columbia Water Company | Docket No. R-2013-2360798 | Rate of Return |
| Penn Estates Utilities, Inc. | 12/11 | Penn Estates, Utilities, Inc. | Docket No. R-2011-2255159 | Capital Structure / Long-Term Debt Cost Rate |
| **South Carolina Public Service Commission** | | | | |
| Blue Granite Water Co. | 12/19 | Blue Granite Water Company | Docket No. 2019-292-WS | Rate of Return |
| Carolina Water Service, Inc. | 02/18 | Carolina Water Service, Inc. | Docket No. 2017-292-WS | Rate of Return |
| Carolina Water Service, Inc. | 06/15 | Carolina Water Service, Inc. | Docket No. 2015-199-WS | Rate of Return |
| Carolina Water Service, Inc. | 11/13 | Carolina Water Service, Inc. | Docket No. 2013-275-WS | Rate of Return |
| United Utility Companies, Inc. | 09/13 | United Utility Companies, Inc. | Docket No. 2013-199-WS | Rate of Return |
| Utility Services of South Carolina, Inc. | 09/13 | Utility Services of South Carolina, Inc. | Docket No. 2013-201-WS | Rate of Return |
| Tega Cay Water Services, Inc. | 11/12 | Tega Cay Water Services, Inc. | Docket No. 2012-177-WS | Capital Structure |
| **Virginia State Corporation Commission** | | | | |
| WGL Holdings, Inc. | 7/18 | Washington Gas Light Company | PUR-2018-00080 | Rate of Return |
| Atmos Energy Corporation | 5/18 | Atmos Energy Corporation | PUR-2018-00014 | Rate of Return |
| Aqua Virginia, Inc. | 7/17 | Aqua Virginia, Inc. | PUR-2017-00082 | Rate of Return |
| Massanutten Public Service Corp. | 08/14 | Massanutten Public Service Corp. | PUE-2014-00035 | Rate of Return / Rate Design |

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.35 | $85.94 | 2.73% | 2.82% | 7.20% | 6.00% | 5.00% | 6.07% | 7.80% | 8.88% | 10.03% |
| Alliant Energy Corporation | LNT | $1.42 | $50.33 | 2.82% | 2.90% | 5.50% | 5.05% | 6.50% | 5.68% | 7.94% | 8.59% | 9.41% |
| Ameren Corporation | AEE | $1.90 | $76.23 | 2.49% | 2.57% | 6.50% | 4.90% | 6.50% | 5.97% | 7.45% | 8.53% | 9.07% |
| American Electric Power Company, Inc. | AEP | $2.68 | $89.81 | 2.98% | 3.06% | 5.70% | 6.10% | 4.00% | 5.27% | 7.04% | 8.33% | 9.18% |
| Avangrid, Inc. | AGR | $1.76 | $49.78 | 3.54% | 3.68% | 7.50% | 6.60% | 10.00% | 8.03% | 10.25% | 11.71% | 13.71% |
| CMS Energy Corporation | CMS | $1.53 | $59.04 | 2.59% | 2.68% | 6.40% | 7.14% | 7.00% | 6.85% | 9.07% | 9.53% | 9.82% |
| DTE Energy Company | DTE | $3.78 | $129.04 | 2.93% | 3.01% | 6.00% | 4.45% | 5.50% | 5.32% | 7.44% | 8.32% | 9.02% |
| Evergy, Inc | EVRG | $1.90 | $61.53 | 3.09% | 3.19% | 6.60% | 6.15% | NMF | 6.38% | 9.33% | 9.56% | 9.79% |
| Hawaiian Electric Industries, Inc. | HE | $1.28 | $44.44 | 2.88% | 2.96% | 5.60% | 6.10% | 4.50% | 5.40% | 7.45% | 8.36% | 9.07% |
| NextEra Energy, Inc. | NEE | $5.00 | $211.08 | 2.37% | 2.47% | 8.00% | 7.99% | 10.50% | 8.83% | 10.45% | 11.30% | 12.99% |
| NorthWestern Corporation | NWE | $2.30 | $70.90 | 3.24% | 3.29% | 2.60% | 3.24% | 3.00% | 2.95% | 5.89% | 6.24% | 6.54% |
| OGE Energy Corp. | OGE | $1.46 | $42.87 | 3.41% | 3.48% | 4.40% | 3.10% | 6.50% | 4.67% | 6.56% | 8.15% | 10.02% |
| Otter Tail Corporation | OTTR | $1.40 | $52.32 | 2.68% | 2.77% | 7.00% | 9.00% | 5.00% | 7.00% | 7.74% | 9.77% | 11.80% |
| Pinnacle West Capital Corporation | PNW | $2.95 | $93.12 | 3.17% | 3.26% | 6.10% | 5.05% | 5.50% | 5.55% | 8.30% | 8.81% | 9.36% |
| PNM Resources, Inc. | PNM | $1.16 | $50.01 | 2.32% | 2.39% | 5.50% | 6.18% | 7.00% | 6.23% | 7.88% | 8.62% | 9.40% |
| Portland General Electric Company | POR | $1.54 | $55.14 | 2.79% | 2.86% | 4.80% | 4.80% | 4.50% | 4.70% | 7.36% | 7.56% | 7.66% |
| Southern Company | SO | $2.48 | $56.51 | 4.39% | 4.46% | 5.00% | 1.37% | 3.50% | 3.29% | 5.79% | 7.75% | 9.50% |
| WEC Energy Group, Inc. | WEC | $2.36 | $87.27 | 2.70% | 2.78% | 5.90% | 5.91% | 6.00% | 5.94% | 8.68% | 8.72% | 8.79% |
| Xcel Energy Inc. | XEL | $1.62 | $60.88 | 2.66% | 2.73% | 4.90% | 5.80% | 5.50% | 5.40% | 7.63% | 8.13% | 8.54% |
| PROXY GROUP MEAN | | | | 2.94% | 3.02% | 5.85% | 5.52% | 5.89% | 5.76% | 7.90% | 8.78% | 9.67% |
| PROXY GROUP MEDIAN | | | | 2.82% | 2.90% | 5.90% | 5.91% | 5.50% | 5.68% | 7.74% | 8.59% | 9.40% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of August 16, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.35 | $83.64 | 2.81% | 2.89% | 7.20% | 6.00% | 5.00% | 6.07% | 7.88% | 8.96% | 10.11% |
| Alliant Energy Corporation | LNT | $1.42 | $48.74 | 2.91% | 3.00% | 5.50% | 5.05% | 6.50% | 5.68% | 8.04% | 8.68% | 9.51% |
| Ameren Corporation | AEE | $1.90 | $74.80 | 2.54% | 2.62% | 6.50% | 4.90% | 6.50% | 5.97% | 7.50% | 8.58% | 9.12% |
| American Electric Power Company, Inc. | AEP | $2.68 | $87.78 | 3.05% | 3.13% | 5.70% | 6.10% | 4.00% | 5.27% | 7.11% | 8.40% | 9.25% |
| Avangrid, Inc. | AGR | $1.76 | $50.50 | 3.49% | 3.63% | 7.50% | 6.60% | 10.00% | 8.03% | 10.20% | 11.66% | 13.66% |
| CMS Energy Corporation | CMS | $1.53 | $57.30 | 2.67% | 2.76% | 6.40% | 7.14% | 7.00% | 6.85% | 9.16% | 9.61% | 9.91% |
| DTE Energy Company | DTE | $3.78 | $127.49 | 2.96% | 3.04% | 6.00% | 4.45% | 5.50% | 5.32% | 7.48% | 8.36% | 9.05% |
| Evergy, Inc | EVRG | $1.90 | $59.72 | 3.18% | 3.28% | 6.60% | 6.15% | NMF | 6.38% | 9.43% | 9.66% | 9.89% |
| Hawaiian Electric Industries, Inc. | HE | $1.28 | $42.95 | 2.98% | 3.06% | 5.60% | 6.10% | 4.50% | 5.40% | 7.55% | 8.46% | 9.17% |
| NextEra Energy, Inc. | NEE | $5.00 | $202.60 | 2.47% | 2.58% | 8.00% | 7.99% | 10.50% | 8.83% | 10.56% | 11.41% | 13.10% |
| NorthWestern Corporation | NWE | $2.30 | $71.12 | 3.23% | 3.28% | 2.60% | 3.24% | 3.00% | 2.95% | 5.88% | 6.23% | 6.53% |
| OGE Energy Corp. | OGE | $1.46 | $42.53 | 3.43% | 3.51% | 4.40% | 3.10% | 6.50% | 4.67% | 6.59% | 8.18% | 10.04% |
| Otter Tail Corporation | OTTR | $1.40 | $51.58 | 2.71% | 2.81% | 7.00% | 9.00% | 5.00% | 7.00% | 7.78% | 9.81% | 11.84% |
| Pinnacle West Capital Corporation | PNW | $2.95 | $94.64 | 3.12% | 3.20% | 6.10% | 5.05% | 5.50% | 5.55% | 8.25% | 8.75% | 9.31% |
| PNM Resources, Inc. | PNM | $1.16 | $48.74 | 2.38% | 2.45% | 5.50% | 6.18% | 7.00% | 6.23% | 7.95% | 8.68% | 9.46% |
| Portland General Electric Company | POR | $1.54 | $53.86 | 2.86% | 2.93% | 4.80% | 4.80% | 4.50% | 4.70% | 7.42% | 7.63% | 7.73% |
| Southern Company | SO | $2.48 | $54.79 | 4.53% | 4.60% | 5.00% | 1.37% | 3.50% | 3.29% | 5.93% | 7.89% | 9.64% |
| WEC Energy Group, Inc. | WEC | $2.36 | $82.92 | 2.85% | 2.93% | 5.90% | 5.91% | 6.00% | 5.94% | 8.83% | 8.87% | 8.93% |
| Xcel Energy Inc. | XEL | $1.62 | $58.90 | 2.75% | 2.82% | 4.90% | 5.80% | 5.50% | 5.40% | 7.72% | 8.22% | 8.63% |
| PROXY GROUP MEAN | | | | 3.00% | 3.08% | 5.85% | 5.52% | 5.89% | 5.76% | 7.96% | 8.84% | 9.73% |
| PROXY GROUP MEDIAN | | | | 2.91% | 3.00% | 5.90% | 5.91% | 5.50% | 5.68% | 7.78% | 8.68% | 9.46% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of August 16, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.35 | $81.34 | 2.89% | 2.98% | 7.20% | 6.00% | 5.00% | 6.07% | 7.96% | 9.04% | 10.19% |
| Alliant Energy Corporation | LNT | $1.42 | $46.78 | 3.04% | 3.12% | 5.50% | 5.05% | 6.50% | 5.68% | 8.16% | 8.81% | 9.63% |
| Ameren Corporation | AEE | $1.90 | $72.12 | 2.63% | 2.71% | 6.50% | 4.90% | 6.50% | 5.97% | 7.60% | 8.68% | 9.22% |
| American Electric Power Company, Inc. | AEP | $2.68 | $83.53 | 3.21% | 3.29% | 5.70% | 6.10% | 4.00% | 5.27% | 7.27% | 8.56% | 9.41% |
| Avangrid, Inc. | AGR | $1.76 | $50.15 | 3.51% | 3.65% | 7.50% | 6.60% | 10.00% | 8.03% | 10.23% | 11.68% | 13.69% |
| CMS Energy Corporation | CMS | $1.53 | $54.94 | 2.79% | 2.88% | 6.40% | 7.14% | 7.00% | 6.85% | 9.27% | 9.73% | 10.02% |
| DTE Energy Company | DTE | $3.78 | $122.91 | 3.08% | 3.16% | 6.00% | 4.45% | 5.50% | 5.32% | 7.59% | 8.47% | 9.17% |
| Evergy, Inc | EVRG | $1.90 | $58.56 | 3.24% | 3.35% | 6.60% | 6.15% | NMF | 6.38% | 9.49% | 9.72% | 9.95% |
| Hawaiian Electric Industries, Inc. | HE | $1.28 | $40.55 | 3.16% | 3.24% | 5.60% | 6.10% | 4.50% | 5.40% | 7.73% | 8.64% | 9.35% |
| NextEra Energy, Inc. | NEE | $5.00 | $192.37 | 2.60% | 2.71% | 8.00% | 7.99% | 10.50% | 8.83% | 10.69% | 11.54% | 13.24% |
| NorthWestern Corporation | NWE | $2.30 | $68.16 | 3.37% | 3.42% | 2.60% | 3.24% | 3.00% | 2.95% | 6.02% | 6.37% | 6.67% |
| OGE Energy Corp. | OGE | $1.46 | $41.85 | 3.49% | 3.57% | 4.40% | 3.10% | 6.50% | 4.67% | 6.64% | 8.24% | 10.10% |
| Otter Tail Corporation | OTTR | $1.40 | $50.39 | 2.78% | 2.88% | 7.00% | 9.00% | 5.00% | 7.00% | 7.85% | 9.88% | 11.90% |
| Pinnacle West Capital Corporation | PNW | $2.95 | $92.44 | 3.19% | 3.28% | 6.10% | 5.05% | 5.50% | 5.55% | 8.32% | 8.83% | 9.39% |
| PNM Resources, Inc. | PNM | $1.16 | $46.21 | 2.51% | 2.59% | 5.50% | 6.18% | 7.00% | 6.23% | 8.08% | 8.82% | 9.60% |
| Portland General Electric Company | POR | $1.54 | $51.30 | 3.00% | 3.07% | 4.80% | 4.80% | 4.50% | 4.70% | 7.57% | 7.77% | 7.87% |
| Southern Company | SO | $2.48 | $51.62 | 4.80% | 4.88% | 5.00% | 1.37% | 3.50% | 3.29% | 6.21% | 8.17% | 9.92% |
| WEC Energy Group, Inc. | WEC | $2.36 | $78.42 | 3.01% | 3.10% | 5.90% | 5.91% | 6.00% | 5.94% | 9.00% | 9.04% | 9.10% |
| Xcel Energy Inc. | XEL | $1.62 | $55.95 | 2.90% | 2.97% | 4.90% | 5.80% | 5.50% | 5.40% | 7.87% | 8.37% | 8.78% |
| PROXY GROUP MEAN | | | | 3.12% | 3.20% | 5.85% | 5.52% | 5.89% | 5.76% | 8.08% | 8.97% | 9.85% |
| PROXY GROUP MEDIAN | | | | 3.04% | 3.12% | 5.90% | 5.91% | 5.50% | 5.68% | 7.87% | 8.81% | 9.60% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of August 16, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 14.48% | 2.43% | 12.04% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 22,034.80 | 0.09% | 0.93% | 13.53% | 14.52% | 0.0126% |
| American Airlines Group Inc | AAL | 11,483.53 | 0.05% | 1.93% | 16.69% | 18.78% | 0.0085% |
| Advance Auto Parts Inc | AAP | 9,750.75 | 0.04% | 0.18% | 15.31% | 15.50% | 0.0060% |
| Apple Inc | AAPL | 933,210.67 | 3.68% | 1.45% | 9.25% | 10.77% | 0.3969% |
| AbbVie Inc | ABBV | 95,258.71 | 0.38% | 6.66% | 5.10% | 11.93% | 0.0449% |
| AmerisourceBergen Corp | ABC | 18,195.15 | 0.07% | 1.84% | 14.01% | 15.98% | 0.0115% |
| ABIOMED Inc | ABMD | 8,758.16 | 0.03% | 0.00% | 29.00% | 29.00% | 0.0100% |
| Abbott Laboratories | ABT | 149,839.97 | 0.59% | 1.47% | 9.58% | 11.12% | 0.0658% |
| Accenture PLC | ACN | 130,029.19 | 0.51% | 1.53% | 10.43% | 12.04% | 0.0618% |
| Adobe Inc | ADBE | 139,539.37 | 0.55% | 0.00% | 17.16% | 17.16% | 0.0945% |
| Analog Devices Inc | ADI | 40,866.01 | 0.16% | 1.88% | 12.10% | 14.10% | 0.0227% |
| Archer-Daniels-Midland Co | ADM | 21,075.90 | 0.08% | 3.73% | 0.10% | 3.83% | 0.0032% |
| Automatic Data Processing Inc | ADP | 72,477.13 | 0.29% | 1.89% | 12.55% | 14.55% | 0.0417% |
| Alliance Data Systems Corp | ADS | 7,086.73 | 0.03% | 1.78% | 9.13% | 10.99% | 0.0031% |
| Autodesk Inc | ADSK | 31,653.77 | 0.12% | 0.00% | 64.51% | 64.51% | 0.0806% |
| Ameren Corp | AEE | 19,416.94 | 0.08% | 2.55% | 5.81% | 8.44% | 0.0065% |
| American Electric Power Co Inc | AEP | 44,555.13 | 0.18% | 3.00% | 5.82% | 8.90% | 0.0157% |
| AES Corp/VA | AES | 10,090.51 | 0.04% | 3.63% | 8.33% | 12.11% | 0.0048% |
| Aflac Inc | AFL | 38,981.18 | 0.15% | 2.06% | 4.15% | 6.25% | 0.0096% |
| Allergan PLC | AGN | 51,911.18 | 0.20% | 1.87% | 5.18% | 7.10% | 0.0145% |
| American International Group Inc | AIG | 47,244.72 | 0.19% | 2.38% | 11.00% | 13.52% | 0.0252% |
| Apartment Investment & Management Co | AIV | 7,542.47 | 0.03% | 3.98% | 7.90% | 12.04% | 0.0036% |
| Assurant Inc | AIZ | 7,612.63 | N/A | 1.98% | N/A | N/A | N/A |
| Arthur J Gallagher & Co | AJG | 16,694.20 | 0.07% | 1.79% | 9.83% | 11.71% | 0.0077% |
| Akamai Technologies Inc | AKAM | 14,295.73 | 0.06% | 0.00% | 12.80% | 12.80% | 0.0072% |
| Albemarle Corp | ALB | 6,686.67 | 0.03% | 2.26% | 10.53% | 12.91% | 0.0034% |
| Align Technology Inc | ALGN | 14,160.31 | 0.06% | 0.00% | 20.51% | 20.51% | 0.0115% |
| Alaska Air Group Inc | ALK | 7,440.71 | 0.03% | 2.29% | 21.50% | 24.03% | 0.0071% |
| Allstate Corp/The | ALL | 33,979.18 | 0.13% | 1.88% | 9.00% | 10.96% | 0.0147% |
| Allegion PLC | ALLE | 8,910.90 | 0.04% | 1.13% | 10.38% | 11.57% | 0.0041% |
| Alexion Pharmaceuticals Inc | ALXN | 24,855.55 | 0.10% | 0.00% | 15.93% | 15.93% | 0.0156% |
| Applied Materials Inc | AMAT | 43,650.57 | 0.17% | 1.78% | 8.98% | 10.84% | 0.0187% |
| Amcor PLC | AMCR | 16,105.41 | 0.06% | 4.68% | 4.92% | 9.71% | 0.0062% |
| Advanced Micro Devices Inc | AMD | 33,847.34 | 0.13% | 0.00% | 18.20% | 18.20% | 0.0243% |
| AMETEK Inc | AME | 19,557.82 | 0.08% | 0.66% | 9.84% | 10.54% | 0.0081% |
| Affiliated Managers Group Inc | AMG | 3,845.57 | 0.02% | 1.69% | 5.86% | 7.60% | 0.0012% |
| Amgen Inc | AMGN | 122,351.04 | 0.48% | 2.83% | 5.88% | 8.79% | 0.0425% |
| Ameriprise Financial Inc | AMP | 16,534.16 | N/A | 2.91% | N/A | N/A | N/A |
| American Tower Corp | AMT | 98,687.79 | 0.39% | 1.69% | 19.95% | 21.81% | 0.0850% |
| Amazon.com Inc | AMZN | 886,705.53 | 3.50% | 0.00% | 44.33% | 44.33% | 1.5522% |
| Arista Networks Inc | ANET | 16,952.19 | 0.07% | 0.00% | 21.39% | 21.39% | 0.0143% |
| ANSYS Inc | ANSS | 17,625.00 | 0.07% | 0.00% | 10.83% | 10.83% | 0.0075% |
| Anthem Inc | ANTM | 70,487.87 | 0.28% | 0.97% | 14.13% | 15.17% | 0.0422% |
| Aon PLC | AON | 45,166.08 | 0.18% | 0.90% | 10.90% | 11.84% | 0.0211% |
| AO Smith Corp | AOS | 7,606.95 | 0.03% | 1.97% | 8.00% | 10.05% | 0.0030% |
| Apache Corp | APA | 7,834.99 | 0.03% | 4.79% | -8.57% | -3.98% | -0.0012% |
| Air Products & Chemicals Inc | APD | 50,408.44 | 0.20% | 1.99% | 12.71% | 14.83% | 0.0295% |
| Amphenol Corp | APH | 25,761.99 | 0.10% | 1.06% | 8.67% | 9.78% | 0.0099% |
| Aptiv PLC | APTV | 20,969.38 | 0.08% | 1.09% | 8.93% | 10.07% | 0.0083% |
| Alexandria Real Estate Equities Inc | ARE | 16,797.13 | 0.07% | 2.68% | 4.77% | 7.51% | 0.0050% |
| Arconic Inc | ARNC | 10,934.28 | 0.04% | 0.43% | 10.90% | 11.35% | 0.0049% |
| Atmos Energy Corp | ATO | 13,054.08 | 0.05% | 1.90% | 7.00% | 8.97% | 0.0046% |
| Activision Blizzard Inc | ATVI | 35,789.43 | 0.14% | 0.78% | 7.30% | 8.11% | 0.0115% |
| AvalonBay Communities Inc | AVB | 28,746.99 | 0.11% | 2.95% | 6.55% | 9.60% | 0.0109% |
| Broadcom Inc | AVGO | 108,984.58 | 0.43% | 3.87% | 13.51% | 17.64% | 0.0759% |
| Avery Dennison Corp | AVY | 9,596.31 | 0.04% | 1.96% | 4.95% | 6.96% | 0.0026% |
| American Water Works Co Inc | AWK | 22,440.68 | 0.09% | 1.59% | 8.58% | 10.24% | 0.0091% |
| American Express Co | AXP | 103,402.23 | 0.41% | 1.31% | 9.16% | 10.52% | 0.0430% |
| AutoZone Inc | AZO | 26,778.97 | 0.11% | 0.00% | 12.58% | 12.58% | 0.0133% |
| Boeing Co/The | BA | 185,947.52 | 0.73% | 2.44% | 7.88% | 10.42% | 0.0765% |
| Bank of America Corp | BAC | 251,603.36 | 0.99% | 2.46% | 9.90% | 12.48% | 0.1240% |
| Baxter International Inc | BAX | 44,403.04 | 0.18% | 0.96% | 11.96% | 12.98% | 0.0228% |
| BB&T Corp | BBT | 35,657.77 | 0.14% | 3.66% | 7.24% | 11.04% | 0.0155% |
| Best Buy Co Inc | BBY | 17,485.98 | 0.07% | 3.05% | 6.89% | 10.05% | 0.0069% |
| Becton Dickinson and Co | BDX | 67,037.71 | 0.26% | 1.31% | 12.19% | 13.58% | 0.0359% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Franklin Resources Inc | BEN | 13,785.35 | 0.05% | 3.80% | 10.00% | 13.99% | 0.0076% |
| Brown-Forman Corp | BF/B | 27,291.04 | 0.11% | 1.20% | 8.41% | 9.66% | 0.0104% |
| Baker Hughes a GE Co | BHGE | 21,858.50 | 0.09% | 3.25% | 41.26% | 45.19% | 0.0390% |
| Biogen Inc | BIIB | 42,732.73 | 0.17% | 0.00% | 5.50% | 5.50% | 0.0093% |
| Bank of New York Mellon Corp/The | BK | 39,902.88 | 0.16% | 2.79% | 6.47% | 9.34% | 0.0147% |
| Booking Holdings Inc | BKNG | 81,715.95 | 0.32% | 0.00% | 17.03% | 17.03% | 0.0549% |
| BlackRock Inc | BLK | 65,242.99 | 0.26% | 3.17% | 8.82% | 12.13% | 0.0313% |
| Ball Corp | BLL | 26,437.50 | 0.10% | 0.63% | 6.70% | 7.35% | 0.0077% |
| Bristol-Myers Squibb Co | BMY | 76,848.31 | 0.30% | 3.50% | 7.96% | 11.60% | 0.0352% |
| Broadridge Financial Solutions Inc | BR | 14,653.33 | N/A | 1.69% | N/A | N/A | N/A |
| Berkshire Hathaway Inc | BRK/B | 490,218.89 | 1.94% | 0.00% | 61.80% | 61.80% | 1.1962% |
| Boston Scientific Corp | BSX | 58,713.83 | 0.23% | 0.00% | 8.88% | 8.88% | 0.0206% |
| BorgWarner Inc | BWA | 6,608.47 | 0.03% | 2.13% | 1.93% | 4.08% | 0.0011% |
| Boston Properties Inc | BXP | 19,817.13 | 0.08% | 3.02% | 4.09% | 7.17% | 0.0056% |
| Citigroup Inc | C | 143,404.90 | 0.57% | 3.03% | 12.43% | 15.65% | 0.0886% |
| Conagra Brands Inc | CAG | 14,340.18 | 0.06% | 2.89% | 7.60% | 10.60% | 0.0060% |
| Cardinal Health Inc | CAH | 12,873.20 | 0.05% | 4.66% | 2.49% | 7.21% | 0.0037% |
| Caterpillar Inc | CAT | 65,502.26 | 0.26% | 3.23% | 13.15% | 16.60% | 0.0429% |
| Chubb Ltd | CB | 70,823.47 | 0.28% | 1.94% | 10.60% | 12.65% | 0.0354% |
| Cboe Global Markets Inc | CBOE | 13,554.86 | 0.05% | 1.09% | 5.35% | 6.47% | 0.0035% |
| CBRE Group Inc | CBRE | 17,371.74 | 0.07% | 0.00% | 7.80% | 7.80% | 0.0054% |
| CBS Corp | CBS | 16,449.63 | 0.06% | 1.71% | 9.95% | 11.75% | 0.0076% |
| Crown Castle International Corp | CCI | 59,419.74 | 0.23% | 3.21% | 17.07% | 20.55% | 0.0482% |
| Carnival Corp | CCL | 30,567.41 | 0.12% | 4.49% | 8.47% | 13.15% | 0.0159% |
| Cadence Design Systems Inc | CDNS | 19,420.21 | 0.08% | 0.00% | 10.07% | 10.07% | 0.0077% |
| Celanese Corp | CE | 13,648.56 | 0.05% | 2.19% | 7.15% | 9.42% | 0.0051% |
| Celgene Corp | CELG | 67,146.15 | 0.27% | 0.00% | 16.10% | 16.10% | 0.0427% |
| Cerner Corp | CERN | 22,494.53 | 0.09% | 0.27% | 13.55% | 13.84% | 0.0123% |
| CF Industries Holdings Inc | CF | 10,518.94 | 0.04% | 2.49% | 19.80% | 22.54% | 0.0094% |
| Citizens Financial Group Inc | CFG | 14,485.60 | 0.06% | 4.19% | 5.42% | 9.72% | 0.0056% |
| Church & Dwight Co Inc | CHD | 19,693.58 | 0.08% | 1.16% | 8.13% | 9.33% | 0.0073% |
| CH Robinson Worldwide Inc | CHRW | 11,347.37 | 0.04% | 2.40% | 8.63% | 11.14% | 0.0050% |
| Charter Communications Inc | CHTR | 95,084.49 | 0.38% | 0.02% | 43.54% | 43.57% | 0.1636% |
| Cigna Corp | CI | 60,885.72 | 0.24% | 0.06% | 11.12% | 11.18% | 0.0269% |
| Cincinnati Financial Corp | CINF | 17,917.99 | N/A | 2.19% | N/A | N/A | N/A |
| Colgate-Palmolive Co | CL | 62,016.71 | 0.24% | 2.40% | 4.52% | 6.98% | 0.0171% |
| Clorox Co/The | CLX | 20,231.96 | 0.08% | 2.56% | 3.93% | 6.54% | 0.0052% |
| Comerica Inc | CMA | 9,160.32 | 0.04% | 4.44% | 12.93% | 17.66% | 0.0064% |
| Comcast Corp | CMCSA | 196,252.47 | 0.77% | 1.93% | 11.50% | 13.54% | 0.1049% |
| CME Group Inc | CME | 76,482.06 | 0.30% | 2.62% | 7.90% | 10.62% | 0.0321% |
| Chipotle Mexican Grill Inc | CMG | 22,655.08 | 0.09% | 0.00% | 21.64% | 21.64% | 0.0194% |
| Cummins Inc | CMI | 23,549.61 | 0.09% | 3.18% | 6.70% | 9.98% | 0.0093% |
| CMS Energy Corp | CMS | 17,367.76 | 0.07% | 2.50% | 7.20% | 9.79% | 0.0067% |
| Centene Corp | CNC | 19,857.19 | 0.08% | 0.00% | 14.93% | 14.93% | 0.0117% |
| CenterPoint Energy Inc | CNP | 13,967.91 | 0.06% | 4.15% | 5.75% | 10.02% | 0.0055% |
| Capital One Financial Corp | COF | 40,213.48 | 0.16% | 1.87% | 5.13% | 7.05% | 0.0112% |
| Cabot Oil & Gas Corp | COG | 6,890.89 | 0.03% | 2.05% | 34.52% | 36.93% | 0.0100% |
| Cooper Cos Inc/The | COO | 16,597.20 | 0.07% | 0.02% | 5.23% | 5.25% | 0.0034% |
| ConocoPhillips | COP | 57,138.99 | 0.23% | 2.41% | 3.45% | 5.90% | 0.0133% |
| Costco Wholesale Corp | COST | 120,546.22 | 0.48% | 0.89% | 10.51% | 11.44% | 0.0545% |
| Coty Inc | COTY | 6,845.24 | 0.03% | 5.42% | 6.71% | 12.31% | 0.0033% |
| Campbell Soup Co | CPB | 12,841.03 | 0.05% | 3.30% | 2.74% | 6.09% | 0.0031% |
| Capri Holdings Ltd | CPRI | 4,280.60 | 0.02% | 0.00% | 5.62% | 5.62% | 0.0009% |
| Copart Inc | CPRT | 17,298.02 | 0.07% | 0.00% | 20.00% | 20.00% | 0.0137% |
| salesforce.com Inc | CRM | 125,939.69 | 0.50% | 0.00% | 22.30% | 22.30% | 0.1109% |
| Cisco Systems Inc | CSCO | 201,023.22 | 0.79% | 3.10% | 6.48% | 9.68% | 0.0768% |
| CSX Corp | CSX | 51,953.26 | 0.21% | 1.43% | 12.17% | 13.69% | 0.0281% |
| Cintas Corp | CTAS | 27,097.57 | 0.11% | 0.85% | 12.23% | 13.14% | 0.0141% |
| CenturyLink Inc | CTL | 12,227.52 | 0.05% | 8.92% | 3.39% | 12.46% | 0.0060% |
| Cognizant Technology Solutions Corp | CTSH | 33,811.26 | 0.13% | 1.39% | 11.05% | 12.52% | 0.0167% |
| Corteva Inc | CTVA | 22,644.16 | 0.09% | 1.44% | 15.65% | 17.20% | 0.0154% |
| Citrix Systems Inc | CTXS | 12,100.59 | 0.05% | 1.51% | 7.80% | 9.37% | 0.0045% |
| CVS Health Corp | CVS | 78,393.94 | 0.31% | 3.31% | 6.16% | 9.58% | 0.0296% |
| Chevron Corp | CVX | 219,855.84 | 0.87% | 4.09% | 1.60% | 5.72% | 0.0497% |
| Concho Resources Inc | CXO | 14,403.28 | 0.06% | 0.89% | 9.20% | 10.14% | 0.0058% |
| Dominion Energy Inc | D | 61,748.32 | 0.24% | 4.76% | 5.18% | 10.06% | 0.0245% |
| Delta Air Lines Inc | DAL | 37,737.64 | 0.15% | 2.58% | 14.63% | 17.39% | 0.0259% |
| DuPont de Nemours Inc | DD | 49,291.30 | 0.19% | 1.67% | 6.55% | 8.27% | 0.0161% |
| Deere & Co | DE | 47,305.24 | 0.19% | 2.00% | 9.54% | 11.64% | 0.0217% |
| Discover Financial Services | DFS | 25,570.67 | 0.10% | 2.06% | 7.28% | 9.42% | 0.0095% |
| Dollar General Corp | DG | 35,108.65 | 0.14% | 0.94% | 10.14% | 11.12% | 0.0154% |
| Quest Diagnostics Inc | DGX | 13,547.81 | 0.05% | 2.09% | 7.86% | 10.03% | 0.0054% |
| DR Horton Inc | DHI | 17,658.90 | 0.07% | 1.26% | 12.60% | 13.93% | 0.0097% |
| Danaher Corp | DHR | 100,682.54 | 0.40% | 0.48% | 13.47% | 13.98% | 0.0556% |
| Walt Disney Co/The | DIS | 243,546.44 | 0.96% | 1.31% | 2.85% | 4.17% | 0.0401% |
| Discovery Inc | DISCA | 20,000.99 | 0.08% | 0.00% | 13.35% | 13.35% | 0.0105% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| DISH Network Corp | DISH | 15,020.05 | 0.06% | 0.00% | -8.61% | -8.61% | -0.0051% |
| Digital Realty Trust Inc | DLR | 26,937.37 | 0.11% | 3.47% | 17.20% | 20.97% | 0.0223% |
| Dollar Tree Inc | DLTR | 22,263.53 | 0.09% | 0.00% | 8.39% | 8.39% | 0.0074% |
| Dover Corp | DOV | 13,194.11 | 0.05% | 2.18% | 10.97% | 13.27% | 0.0069% |
| Dow Inc | DOW | 33,080.37 | 0.13% | 5.85% | 14.15% | 20.41% | 0.0267% |
| Duke Realty Corp | DRE | 12,021.63 | 0.05% | 2.62% | 4.74% | 7.42% | 0.0035% |
| Darden Restaurants Inc | DRI | 14,381.72 | 0.06% | 3.03% | 10.76% | 13.95% | 0.0079% |
| DTE Energy Co | DTE | 23,699.08 | 0.09% | 2.95% | 5.53% | 8.55% | 0.0080% |
| Duke Energy Corp | DUK | 65,352.56 | 0.26% | 4.22% | 5.07% | 9.40% | 0.0242% |
| DaVita Inc | DVA | 9,268.55 | 0.04% | 0.00% | 18.68% | 18.68% | 0.0068% |
| Devon Energy Corp | DVN | 9,110.67 | 0.04% | 1.51% | 6.63% | 8.20% | 0.0029% |
| DXC Technology Co | DXC | 8,327.79 | 0.03% | 2.56% | 3.77% | 6.38% | 0.0021% |
| Electronic Arts Inc | EA | 26,394.00 | 0.10% | 0.00% | 8.54% | 8.54% | 0.0089% |
| eBay Inc | EBAY | 33,567.32 | 0.13% | 1.39% | 12.07% | 13.55% | 0.0180% |
| Ecolab Inc | ECL | 59,509.96 | 0.23% | 0.90% | 13.13% | 14.09% | 0.0331% |
| Consolidated Edison Inc | ED | 28,962.97 | 0.11% | 3.39% | 4.18% | 7.64% | 0.0087% |
| Equifax Inc | EFX | 17,375.91 | 0.07% | 1.09% | 8.74% | 9.87% | 0.0068% |
| Edison International | EIX | 25,961.49 | 0.10% | 3.39% | 5.05% | 8.52% | 0.0087% |
| Estee Lauder Cos Inc/The | EL | 64,854.80 | 0.26% | 0.92% | 12.08% | 13.06% | 0.0334% |
| Eastman Chemical Co | EMN | 8,971.75 | 0.04% | 3.64% | 7.93% | 11.72% | 0.0042% |
| Emerson Electric Co | EMR | 35,626.68 | 0.14% | 3.39% | 8.19% | 11.72% | 0.0165% |
| EOG Resources Inc | EOG | 44,083.94 | 0.17% | 1.35% | 6.50% | 7.89% | 0.0137% |
| Equinix Inc | EQIX | 46,804.09 | 0.18% | 1.78% | 19.24% | 21.20% | 0.0392% |
| Equity Residential | EQR | 30,276.42 | 0.12% | 2.79% | 8.47% | 11.38% | 0.0136% |
| Eversource Energy | ES | 25,448.06 | 0.10% | 2.72% | 5.99% | 8.80% | 0.0088% |
| Essex Property Trust Inc | ESS | 20,685.86 | 0.08% | 2.48% | 8.07% | 10.66% | 0.0087% |
| E*TRADE Financial Corp | ETFC | 9,853.96 | 0.04% | 1.19% | 12.73% | 14.00% | 0.0054% |
| Eaton Corp PLC | ETN | 32,474.40 | 0.13% | 3.68% | 8.60% | 12.44% | 0.0160% |
| Entergy Corp | ETR | 21,710.22 | 0.09% | 3.35% | 1.90% | 5.28% | 0.0045% |
| Evergy Inc | EVRG | 15,175.88 | 0.06% | 2.98% | 7.62% | 10.72% | 0.0064% |
| Edwards Lifesciences Corp | EW | 45,615.97 | 0.18% | 0.00% | 14.75% | 14.75% | 0.0266% |
| Exelon Corp | EXC | 43,773.94 | 0.17% | 3.21% | 2.66% | 5.90% | 0.0102% |
| Expeditors International of Washington I | EXPD | 12,194.54 | 0.05% | 1.37% | 9.73% | 11.17% | 0.0054% |
| Expedia Group Inc | EXPE | 18,839.90 | 0.07% | 0.98% | 21.16% | 22.25% | 0.0166% |
| Extra Space Storage Inc | EXR | 15,501.71 | 0.06% | 2.95% | 4.54% | 7.56% | 0.0046% |
| Ford Motor Co | F | 35,749.00 | 0.14% | 6.70% | 2.58% | 9.37% | 0.0132% |
| Diamondback Energy Inc | FANG | 15,857.61 | 0.06% | 0.68% | 17.36% | 18.10% | 0.0113% |
| Fastenal Co | FAST | 17,191.44 | 0.07% | 2.90% | 7.15% | 10.15% | 0.0069% |
| Facebook Inc | FB | 524,087.01 | 2.07% | 0.00% | 19.37% | 19.37% | 0.4007% |
| Fortune Brands Home & Security Inc | FBHS | 7,073.77 | 0.03% | 1.72% | 10.11% | 11.91% | 0.0033% |
| Freeport-McMoRan Inc | FCX | 13,203.10 | 0.05% | 2.20% | -7.37% | -5.25% | -0.0027% |
| FedEx Corp | FDX | 40,695.15 | 0.16% | 1.71% | 20.72% | 22.60% | 0.0363% |
| FirstEnergy Corp | FE | 23,773.91 | 0.09% | 3.40% | 1.29% | 4.71% | 0.0044% |
| F5 Networks Inc | FFIV | 7,741.14 | 0.03% | 0.00% | 10.29% | 10.29% | 0.0031% |
| Fidelity National Information Services I | FIS | 84,845.48 | 0.34% | 1.01% | 8.97% | 10.02% | 0.0336% |
| Fiserv Inc | FISV | 72,887.67 | 0.29% | 0.00% | 15.60% | 15.60% | 0.0449% |
| Fifth Third Bancorp | FITB | 18,751.57 | 0.07% | 3.74% | 4.65% | 8.47% | 0.0063% |
| FLIR Systems Inc | FLIR | 6,370.77 | N/A | 1.45% | N/A | N/A | N/A |
| Flowserve Corp | FLS | 5,557.68 | 0.02% | 1.83% | 15.19% | 17.16% | 0.0038% |
| FleetCor Technologies Inc | FLT | 25,214.64 | 0.10% | 0.00% | 18.19% | 18.19% | 0.0181% |
| FMC Corp | FMC | 11,163.73 | 0.04% | 1.87% | 9.00% | 10.95% | 0.0048% |
| Fox Corp | FOXA | 20,479.18 | 0.08% | 1.09% | 1.51% | 2.61% | 0.0021% |
| First Republic Bank/CA | FRC | 15,180.87 | 0.06% | 0.82% | 10.00% | 10.85% | 0.0065% |
| Federal Realty Investment Trust | FRT | 9,792.80 | 0.04% | 3.20% | 5.54% | 8.83% | 0.0034% |
| TechnipFMC PLC | FTI | 10,608.41 | 0.04% | 2.30% | 16.08% | 18.56% | 0.0078% |
| Fortinet Inc | FTNT | 13,792.17 | 0.05% | 0.00% | 16.10% | 16.10% | 0.0088% |
| Fortive Corp | FTV | 23,128.31 | 0.09% | 0.45% | 10.10% | 10.57% | 0.0097% |
| General Dynamics Corp | GD | 53,248.41 | 0.21% | 2.18% | 8.39% | 10.66% | 0.0224% |
| General Electric Co | GE | 76,710.96 | 0.30% | 0.48% | 5.70% | 6.19% | 0.0188% |
| Gilead Sciences Inc | GILD | 79,964.00 | 0.32% | 3.98% | 8.52% | 12.66% | 0.0400% |
| General Mills Inc | GIS | 33,204.06 | 0.13% | 3.60% | 6.17% | 9.88% | 0.0130% |
| Globe Life Inc | GL | 9,510.42 | 0.04% | 0.78% | 7.60% | 8.41% | 0.0032% |
| Corning Inc | GLW | 21,575.33 | 0.09% | 2.93% | 11.20% | 14.29% | 0.0122% |
| General Motors Co | GM | 52,825.98 | 0.21% | 4.14% | 10.46% | 14.81% | 0.0309% |
| Alphabet Inc | GOOGL | 817,065.59 | 3.23% | 0.00% | 12.87% | 12.87% | 0.4151% |
| Genuine Parts Co | GPC | 13,116.38 | 0.05% | 3.37% | 5.35% | 8.81% | 0.0046% |
| Global Payments Inc | GPN | 24,715.97 | 0.10% | 0.03% | 17.13% | 17.16% | 0.0167% |
| Gap Inc/The | GPS | 6,036.21 | 0.02% | 6.11% | 6.63% | 12.94% | 0.0031% |
| Garmin Ltd | GRMN | 14,670.17 | 0.06% | 3.01% | 7.03% | 10.14% | 0.0059% |
| Goldman Sachs Group Inc/The | GS | 74,615.97 | 0.29% | 2.10% | 0.64% | 2.75% | 0.0081% |
| WW Grainger Inc | GWW | 14,693.83 | 0.06% | 2.10% | 12.33% | 14.57% | 0.0085% |
| Halliburton Co | HAL | 16,528.84 | 0.07% | 3.59% | 8.74% | 12.49% | 0.0081% |
| Hasbro Inc | HAS | 14,433.59 | 0.06% | 2.37% | 9.53% | 12.02% | 0.0068% |
| Huntington Bancshares Inc/OH | HBAN | 13,419.29 | 0.05% | 4.48% | 4.99% | 9.58% | 0.0051% |
| Hanesbrands Inc | HBI | 4,924.22 | 0.02% | 4.57% | 5.08% | 9.77% | 0.0019% |
| HCA Healthcare Inc | HCA | 42,258.00 | 0.17% | 1.27% | 10.78% | 12.12% | 0.0202% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($million) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| HCP Inc | HCP | 16,933.48 | 0.07% | 4.29% | 2.94% | 7.30% | 0.0049% |
| Home Depot Inc/The | HD | 224,073.26 | 0.88% | 2.67% | 7.16% | 9.93% | 0.0878% |
| Hess Corp | HES | 18,214.03 | 0.07% | 1.77% | -5.43% | -3.71% | -0.0027% |
| HollyFrontier Corp | HFC | 7,299.04 | 0.03% | 3.01% | -0.31% | 2.70% | 0.0008% |
| Hartford Financial Services Group Inc/Th | HIG | 21,141.66 | 0.08% | 2.11% | 9.50% | 11.71% | 0.0098% |
| Huntington Ingalls Industries Inc | HII | 8,548.81 | 0.03% | 1.67% | 40.00% | 42.00% | 0.0142% |
| Hilton Worldwide Holdings Inc | HLT | 26,680.34 | 0.11% | 0.65% | 12.28% | 12.97% | 0.0137% |
| Harley-Davidson Inc | HOG | 5,056.16 | 0.02% | 4.75% | 5.90% | 10.79% | 0.0022% |
| Hologic Inc | HOLX | 13,485.59 | 0.05% | 0.00% | 8.58% | 8.58% | 0.0046% |
| Honeywell International Inc | HON | 118,740.41 | 0.47% | 2.02% | 7.70% | 9.80% | 0.0459% |
| Helmerich & Payne Inc | HP | 4,312.78 | 0.02% | 7.23% | 22.74% | 30.79% | 0.0052% |
| Hewlett Packard Enterprise Co | HPE | 17,141.10 | 0.07% | 3.58% | 5.44% | 9.12% | 0.0062% |
| HP Inc | HPQ | 28,740.05 | 0.11% | 3.33% | 3.11% | 6.49% | 0.0074% |
| H&R Block Inc | HRB | 5,566.81 | 0.02% | 3.75% | 10.00% | 13.94% | 0.0031% |
| Hormel Foods Corp | HRL | 22,127.86 | 0.09% | 2.03% | 5.70% | 7.78% | 0.0068% |
| Henry Schein Inc | HSIC | 9,155.01 | 0.04% | 0.00% | 3.51% | 3.51% | 0.0013% |
| Host Hotels & Resorts Inc | HST | 11,568.97 | 0.05% | 5.34% | 19.82% | 25.70% | 0.0117% |
| Hershey Co/The | HSY | 32,576.95 | 0.13% | 1.93% | 7.07% | 9.07% | 0.0117% |
| Humana Inc | HUM | 40,121.52 | 0.16% | 0.71% | 12.83% | 13.58% | 0.0215% |
| International Business Machines Corp | IBM | 118,494.66 | 0.47% | 4.82% | 1.92% | 6.79% | 0.0318% |
| Intercontinental Exchange Inc | ICE | 51,373.22 | 0.20% | 1.19% | 9.35% | 10.60% | 0.0215% |
| IDEXX Laboratories Inc | IDXX | 23,710.07 | 0.09% | 0.00% | 18.85% | 18.85% | 0.0176% |
| IDEX Corp | IEX | 12,438.94 | 0.05% | 1.17% | 11.20% | 12.43% | 0.0061% |
| International Flavors & Fragrances Inc | IFF | 12,042.08 | 0.05% | 2.59% | 7.80% | 10.49% | 0.0050% |
| Illumina Inc | ILMN | 42,066.99 | 0.17% | 0.00% | 23.74% | 23.74% | 0.0394% |
| Incyte Corp | INCY | 17,876.34 | 0.07% | 0.00% | 43.15% | 43.15% | 0.0305% |
| IHS Markit Ltd | INFO | 26,000.35 | 0.10% | 0.00% | 11.08% | 11.08% | 0.0114% |
| Intel Corp | INTC | 205,995.00 | 0.81% | 2.68% | 6.74% | 9.51% | 0.0773% |
| Intuit Inc | INTU | 70,244.59 | 0.28% | 0.69% | 16.16% | 16.90% | 0.0469% |
| International Paper Co | IP | 15,316.69 | 0.06% | 5.16% | 4.55% | 9.83% | 0.0059% |
| Interpublic Group of Cos Inc/The | IPG | 7,783.19 | 0.03% | 4.68% | 12.35% | 17.32% | 0.0053% |
| IPG Photonics Corp | IPGP | 6,353.18 | 0.03% | 0.00% | 6.13% | 6.13% | 0.0015% |
| IQVIA Holdings Inc | IQV | 30,404.79 | 0.12% | 0.00% | 17.75% | 17.75% | 0.0213% |
| Ingersoll-Rand PLC | IR | 28,477.06 | 0.11% | 1.82% | 7.74% | 9.63% | 0.0108% |
| Iron Mountain Inc | IRM | 9,040.99 | 0.04% | 7.80% | 3.81% | 11.76% | 0.0042% |
| Intuitive Surgical Inc | ISRG | 57,102.31 | 0.23% | 0.00% | 14.30% | 14.30% | 0.0322% |
| Gartner Inc | IT | 11,653.84 | 0.05% | 0.00% | 13.08% | 13.08% | 0.0060% |
| Illinois Tool Works Inc | ITW | 48,592.89 | 0.19% | 2.70% | 6.66% | 9.44% | 0.0181% |
| Invesco Ltd | IVZ | 7,352.27 | 0.03% | 7.91% | 7.00% | 15.19% | 0.0044% |
| JB Hunt Transport Services Inc | JBHT | 10,465.41 | 0.04% | 1.05% | 12.13% | 13.25% | 0.0055% |
| Johnson Controls International plc | JCI | 33,682.26 | 0.13% | 2.53% | 7.57% | 10.20% | 0.0136% |
| Jacobs Engineering Group Inc | JEC | 11,311.38 | 0.04% | 0.65% | 14.70% | 15.40% | 0.0069% |
| Jefferies Financial Group Inc | JEF | 5,568.05 | N/A | 2.69% | N/A | N/A | N/A |
| Jack Henry & Associates Inc | JKHY | 10,956.74 | 0.04% | 1.08% | 9.20% | 10.32% | 0.0045% |
| Johnson & Johnson | JNJ | 346,680.78 | 1.37% | 2.85% | 6.09% | 9.03% | 0.1237% |
| Juniper Networks Inc | JNPR | 8,271.91 | 0.03% | 3.15% | 7.74% | 11.02% | 0.0036% |
| JPMorgan Chase & Co | JPM | 344,433.08 | 1.36% | 3.15% | 4.65% | 7.87% | 0.1071% |
| Nordstrom Inc | JWN | 3,915.78 | 0.02% | 6.03% | 5.97% | 12.17% | 0.0019% |
| Kellogg Co | K | 21,725.50 | 0.09% | 3.61% | 0.89% | 4.51% | 0.0039% |
| KeyCorp | KEY | 16,483.54 | 0.07% | 4.32% | 4.83% | 9.26% | 0.0060% |
| Keysight Technologies Inc | KEYS | 16,124.37 | N/A | 0.00% | N/A | N/A | N/A |
| Kraft Heinz Co/The | KHC | 30,999.98 | 0.12% | 6.30% | -0.76% | 5.51% | 0.0067% |
| Kimco Realty Corp | KIM | 7,880.56 | 0.03% | 6.09% | 3.92% | 10.12% | 0.0032% |
| KLA Corp | KLAC | 21,999.75 | 0.09% | 2.26% | 12.94% | 15.35% | 0.0133% |
| Kimberly-Clark Corp | KMB | 48,426.86 | 0.19% | 2.91% | 4.63% | 7.61% | 0.0145% |
| Kinder Morgan Inc/DE | KMI | 45,570.40 | 0.18% | 4.94% | 13.90% | 19.19% | 0.0345% |
| CarMax Inc | KMX | 14,079.79 | 0.06% | 0.00% | 10.61% | 10.61% | 0.0059% |
| Coca-Cola Co/The | KO | 232,658.65 | 0.92% | 2.96% | 7.09% | 10.16% | 0.0933% |
| Kroger Co/The | KR | 18,100.78 | 0.07% | 2.61% | 5.68% | 8.36% | 0.0060% |
| Kohl's Corp | KSS | 7,373.80 | 0.03% | 5.89% | 6.10% | 12.17% | 0.0035% |
| Kansas City Southern | KSU | 11,996.65 | 0.05% | 1.24% | 12.73% | 14.05% | 0.0067% |
| Loews Corp | L | 14,771.26 | N/A | 0.51% | N/A | N/A | N/A |
| L Brands Inc | LB | 5,626.29 | 0.02% | 5.90% | 9.23% | 15.40% | 0.0034% |
| Leidos Holdings Inc | LDOS | 12,053.97 | 0.05% | 1.55% | 10.00% | 11.63% | 0.0055% |
| Leggett & Platt Inc | LEG | 5,062.91 | N/A | 4.10% | N/A | N/A | N/A |
| Lennar Corp | LEN | 15,485.26 | 0.06% | 0.32% | 9.42% | 9.76% | 0.0060% |
| Laboratory Corp of America Holdings | LH | 16,232.86 | 0.06% | 0.00% | 8.18% | 8.18% | 0.0052% |
| L3Harris Technologies Inc | LHX | 46,689.17 | N/A | 1.36% | N/A | N/A | N/A |
| Linde PLC | LIN | 102,058.27 | 0.40% | 1.93% | 13.95% | 16.01% | 0.0645% |
| LKQ Corp | LKQ | 7,880.80 | 0.03% | 0.00% | 12.80% | 12.80% | 0.0040% |
| Eli Lilly & Co | LLY | 106,699.65 | 0.42% | 2.27% | 9.75% | 12.13% | 0.0511% |
| Lockheed Martin Corp | LMT | 106,463.86 | 0.42% | 2.39% | 9.81% | 12.31% | 0.0517% |
| Lincoln National Corp | LNC | 10,708.31 | 0.04% | 2.82% | 9.00% | 11.95% | 0.0051% |
| Alliant Energy Corp | LNT | 12,263.21 | 0.05% | 2.75% | 5.61% | 8.44% | 0.0041% |
| Lowe's Cos Inc | LOW | 73,531.52 | 0.29% | 2.23% | 14.66% | 17.05% | 0.0495% |
| Lam Research Corp | LRCX | 29,624.65 | 0.12% | 2.18% | 15.80% | 18.15% | 0.0212% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Southwest Airlines Co | LUV | 26,762.97 | 0.11% | 1.44% | 8.25% | 9.75% | 0.0103% |
| Lamb Weston Holdings Inc | LW | 10,023.85 | 0.04% | 1.21% | 7.50% | 8.76% | 0.0035% |
| LyondellBasell Industries NV | LYB | 24,891.99 | 0.10% | 5.68% | 8.00% | 13.90% | 0.0137% |
| Macy's Inc | M | 4,936.22 | 0.02% | 9.45% | 4.07% | 13.71% | 0.0027% |
| Mastercard Inc | MA | 278,354.54 | 1.10% | 0.46% | 17.26% | 17.76% | 0.1952% |
| Mid-America Apartment Communities Inc | MAA | 14,165.47 | N/A | 3.09% | N/A | N/A | N/A |
| Macerich Co/The | MAC | 4,139.08 | 0.02% | 10.24% | -0.17% | 10.06% | 0.0016% |
| Marriott International Inc/MD | MAR | 42,428.00 | 0.17% | 1.44% | 7.34% | 8.83% | 0.0148% |
| Masco Corp | MAS | 11,132.48 | 0.04% | 1.23% | 10.51% | 11.80% | 0.0052% |
| McDonald's Corp | MCD | 165,915.77 | 0.66% | 2.15% | 8.67% | 10.91% | 0.0715% |
| Microchip Technology Inc | MCHP | 21,038.29 | 0.08% | 1.57% | 10.14% | 11.78% | 0.0098% |
| McKesson Corp | MCK | 26,864.72 | 0.11% | 1.13% | 2.39% | 3.53% | 0.0037% |
| Moody's Corp | MCO | 40,543.67 | 0.16% | 0.97% | 11.75% | 12.78% | 0.0205% |
| Mondelez International Inc | MDLZ | 78,654.89 | 0.31% | 1.98% | 7.86% | 9.92% | 0.0308% |
| Medtronic PLC | MDT | 137,817.26 | 0.54% | 2.05% | 6.30% | 8.42% | 0.0458% |
| MetLife Inc | MET | 42,467.90 | 0.17% | 3.83% | 8.39% | 12.38% | 0.0208% |
| MGM Resorts International | MGM | 14,761.59 | 0.06% | 1.84% | 12.42% | 14.37% | 0.0084% |
| Mohawk Industries Inc | MHK | 8,033.46 | 0.03% | 0.00% | 5.28% | 5.28% | 0.0017% |
| McCormick & Co Inc/MD | MKC | 22,520.93 | 0.09% | 1.31% | 6.20% | 7.55% | 0.0067% |
| MarketAxess Holdings Inc | MKTX | 13,826.87 | N/A | 0.56% | N/A | N/A | N/A |
| Martin Marietta Materials Inc | MLM | 15,912.09 | 0.06% | 0.78% | 15.99% | 16.84% | 0.0106% |
| Marsh & McLennan Cos Inc | MMC | 49,507.11 | 0.20% | 1.79% | 12.22% | 14.12% | 0.0276% |
| 3M Co | MMM | 92,907.57 | 0.37% | 3.50% | 6.95% | 10.58% | 0.0388% |
| Monster Beverage Corp | MNST | 31,156.20 | 0.12% | 0.00% | 14.30% | 14.30% | 0.0176% |
| Altria Group Inc | MO | 86,829.10 | 0.34% | 7.10% | 6.70% | 14.04% | 0.0481% |
| Mosaic Co/The | MOS | 7,617.02 | 0.03% | 0.98% | 12.63% | 13.68% | 0.0041% |
| Marathon Petroleum Corp | MPC | 30,427.52 | 0.12% | 4.62% | 10.23% | 15.09% | 0.0181% |
| Merck & Co Inc | MRK | 217,785.47 | 0.86% | 2.59% | 11.52% | 14.25% | 0.1225% |
| Marathon Oil Corp | MRO | 10,010.32 | 0.04% | 1.61% | 1.55% | 3.17% | 0.0013% |
| Morgan Stanley | MS | 66,011.55 | 0.26% | 3.28% | 8.26% | 11.67% | 0.0304% |
| MSCI Inc | MSCI | 19,161.37 | 0.08% | 1.10% | 5.83% | 6.95% | 0.0053% |
| Microsoft Corp | MSFT | 1,039,408.28 | 4.10% | 1.45% | 9.92% | 11.44% | 0.4697% |
| Motorola Solutions Inc | MSI | 28,694.08 | 0.11% | 1.33% | 7.05% | 8.42% | 0.0095% |
| M&T Bank Corp | MTB | 19,718.51 | 0.08% | 2.86% | 5.33% | 8.27% | 0.0064% |
| Mettler-Toledo International Inc | MTD | 16,369.82 | 0.06% | 0.00% | 13.47% | 13.47% | 0.0087% |
| Micron Technology Inc | MU | 48,070.64 | 0.19% | 0.00% | -0.69% | -0.69% | -0.0013% |
| Maxim Integrated Products Inc | MXIM | 14,740.92 | 0.06% | 3.38% | 8.53% | 12.06% | 0.0070% |
| Mylan NV | MYL | 9,559.07 | 0.04% | 0.00% | -5.72% | -5.72% | -0.0022% |
| Noble Energy Inc | NBL | 10,287.22 | 0.04% | 2.14% | 16.58% | 18.90% | 0.0077% |
| Norwegian Cruise Line Holdings Ltd | NCLH | 10,883.35 | 0.04% | 0.19% | 9.96% | 10.15% | 0.0044% |
| Nasdaq Inc | NDAQ | 16,062.00 | 0.06% | 1.89% | 13.00% | 15.01% | 0.0095% |
| NextEra Energy Inc | NEE | 104,219.18 | 0.41% | 2.29% | 5.33% | 7.69% | 0.0316% |
| Newmont Goldcorp Corp | NEM | 31,631.50 | 0.12% | 1.45% | 5.75% | 7.24% | 0.0090% |
| Netflix Inc | NFLX | 132,576.40 | 0.52% | 0.00% | 43.20% | 43.20% | 0.2261% |
| NiSource Inc | NI | 10,983.88 | 0.04% | 2.73% | 5.28% | 8.08% | 0.0035% |
| NIKE Inc | NKE | 125,789.80 | 0.50% | 1.15% | 13.76% | 14.99% | 0.0744% |
| Nektar Therapeutics | NKTR | 3,172.47 | 0.01% | 0.00% | -8.60% | -8.60% | -0.0011% |
| Nielsen Holdings PLC | NLSN | 7,237.96 | 0.03% | 6.93% | 12.00% | 19.34% | 0.0055% |
| Northrop Grumman Corp | NOC | 62,249.70 | 0.25% | 1.42% | 8.37% | 9.85% | 0.0242% |
| National Oilwell Varco Inc | NOV | 7,193.11 | 0.03% | 1.07% | 59.18% | 60.57% | 0.0172% |
| NRG Energy Inc | NRG | 8,973.48 | 0.04% | 0.34% | 35.23% | 35.63% | 0.0126% |
| Norfolk Southern Corp | NSC | 45,569.37 | 0.18% | 2.02% | 13.82% | 15.98% | 0.0287% |
| NetApp Inc | NTAP | 11,173.24 | 0.04% | 4.10% | 5.85% | 10.07% | 0.0044% |
| Northern Trust Corp | NTRS | 18,695.49 | 0.07% | 2.97% | 7.25% | 10.33% | 0.0076% |
| Nucor Corp | NUE | 14,781.94 | 0.06% | 3.29% | 0.35% | 3.64% | 0.0021% |
| NVIDIA Corp | NVDA | 97,172.04 | 0.38% | 0.41% | 9.89% | 10.32% | 0.0396% |
| Newell Brands Inc | NWL | 6,706.66 | 0.03% | 5.80% | -3.42% | 2.28% | 0.0006% |
| News Corp | NWSA | 8,129.25 | 0.03% | 1.42% | -14.23% | -12.91% | -0.0041% |
| Realty Income Corp | O | 23,170.17 | 0.09% | 3.73% | 4.07% | 7.88% | 0.0072% |
| ONEOK Inc | OKE | 28,618.70 | 0.11% | 5.11% | 13.18% | 18.63% | 0.0211% |
| Omnicom Group Inc | OMC | 16,771.08 | 0.07% | 3.37% | 3.87% | 7.30% | 0.0048% |
| Oracle Corp | ORCL | 178,766.54 | 0.71% | 1.70% | 7.63% | 9.40% | 0.0664% |
| O'Reilly Automotive Inc | ORLY | 29,200.35 | 0.12% | 0.00% | 13.64% | 13.64% | 0.0157% |
| Occidental Petroleum Corp | OXY | 39,866.96 | 0.16% | 7.00% | 12.20% | 19.63% | 0.0309% |
| Paychex Inc | PAYX | 29,275.88 | 0.12% | 3.04% | 7.15% | 10.30% | 0.0119% |
| People's United Financial Inc | PBCT | 5,781.67 | 0.02% | 4.87% | 2.00% | 6.92% | 0.0016% |
| PACCAR Inc | PCAR | 22,333.88 | 0.09% | 5.27% | 4.90% | 10.30% | 0.0091% |
| Public Service Enterprise Group Inc | PEG | 29,377.48 | 0.12% | 3.24% | 5.32% | 8.64% | 0.0100% |
| PepsiCo Inc | PEP | 184,222.81 | 0.73% | 2.87% | 5.45% | 8.40% | 0.0611% |
| Pfizer Inc | PFE | 191,650.83 | 0.76% | 4.14% | 3.88% | 8.09% | 0.0612% |
| Principal Financial Group Inc | PFG | 14,857.06 | 0.06% | 4.12% | 6.87% | 11.14% | 0.0065% |
| Procter & Gamble Co/The | PG | 298,219.31 | 1.18% | 2.53% | 7.40% | 10.03% | 0.1180% |
| Progressive Corp/The | PGR | 45,304.34 | 0.18% | 3.56% | 6.23% | 9.91% | 0.0177% |
| Parker-Hannifin Corp | PH | 20,759.14 | 0.08% | 2.07% | 8.24% | 10.39% | 0.0085% |
| PulteGroup Inc | PHM | 8,794.19 | 0.03% | 1.38% | 8.25% | 9.69% | 0.0034% |
| Packaging Corp of America | PKG | 9,587.45 | 0.04% | 3.16% | 10.00% | 13.31% | 0.0050% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| PerkinElmer Inc | PKI | 9,146.01 | 0.04% | 0.34% | 16.84% | 17.21% | 0.0062% |
| Prologis Inc | PLD | 51,963.39 | 0.21% | 2.57% | 7.34% | 10.01% | 0.0205% |
| Philip Morris International Inc | PM | 132,106.36 | 0.52% | 5.47% | 7.67% | 13.36% | 0.0697% |
| PNC Financial Services Group Inc/The | PNC | 56,547.63 | 0.22% | 3.31% | 7.64% | 11.07% | 0.0247% |
| Pentair PLC | PNR | 6,080.02 | 0.02% | 1.99% | 7.15% | 9.21% | 0.0022% |
| Pinnacle West Capital Corp | PNW | 10,570.04 | 0.04% | 3.30% | 5.34% | 8.74% | 0.0036% |
| PPG Industries Inc | PPG | 26,162.35 | 0.10% | 1.79% | 6.82% | 8.67% | 0.0090% |
| PPL Corp | PPL | 21,229.31 | 0.08% | 5.63% | -0.30% | 5.32% | 0.0045% |
| Perrigo Co PLC | PRGO | 6,283.00 | 0.02% | 1.67% | -0.50% | 1.17% | 0.0003% |
| Prudential Financial Inc | PRU | 32,976.06 | 0.13% | 4.88% | 11.43% | 16.59% | 0.0216% |
| Public Storage | PSA | 45,182.41 | 0.18% | 3.10% | 4.10% | 7.27% | 0.0130% |
| Phillips 66 | PSX | 44,329.38 | 0.18% | 3.51% | 2.20% | 5.75% | 0.0101% |
| PVH Corp | PVH | 5,297.86 | 0.02% | 0.21% | 8.12% | 8.34% | 0.0017% |
| Quanta Services Inc | PWR | 4,732.30 | 0.02% | 0.36% | 22.00% | 22.40% | 0.0042% |
| Pioneer Natural Resources Co | PXD | 20,827.77 | 0.08% | 0.71% | 23.85% | 24.64% | 0.0203% |
| PayPal Holdings Inc | PYPL | 124,915.86 | 0.49% | 0.00% | 19.11% | 19.11% | 0.0943% |
| QUALCOMM Inc | QCOM | 89,083.40 | 0.35% | 3.40% | 14.37% | 18.01% | 0.0634% |
| Qorvo Inc | QRVO | 8,434.56 | 0.03% | 0.28% | 10.76% | 11.06% | 0.0037% |
| Royal Caribbean Cruises Ltd | RCL | 22,041.63 | 0.09% | 2.72% | 11.11% | 13.98% | 0.0122% |
| Everest Re Group Ltd | RE | 10,156.13 | 0.04% | 2.28% | 10.00% | 12.40% | 0.0050% |
| Regency Centers Corp | REG | 10,933.85 | 0.04% | 3.55% | 4.62% | 8.25% | 0.0036% |
| Regeneron Pharmaceuticals Inc | REGN | 32,603.74 | 0.13% | 0.00% | 11.88% | 11.88% | 0.0153% |
| Regions Financial Corp | RF | 14,058.61 | 0.06% | 4.26% | 8.21% | 12.64% | 0.0070% |
| Robert Half International Inc | RHI | 6,470.56 | 0.03% | 2.23% | -1.99% | 0.22% | 0.0001% |
| Raymond James Financial Inc | RJF | 10,517.37 | 0.04% | 1.74% | 11.10% | 12.93% | 0.0054% |
| Ralph Lauren Corp | RL | 6,713.64 | 0.03% | 3.13% | 8.01% | 11.26% | 0.0030% |
| ResMed Inc | RMD | 19,315.14 | 0.08% | 1.21% | 11.37% | 12.64% | 0.0096% |
| Rockwell Automation Inc | ROK | 17,587.42 | 0.07% | 2.54% | 11.90% | 14.59% | 0.0101% |
| Rollins Inc | ROL | 10,823.42 | N/A | 1.72% | N/A | N/A | N/A |
| Roper Technologies Inc | ROP | 37,171.29 | 0.15% | 0.54% | 13.03% | 13.61% | 0.0200% |
| Ross Stores Inc | ROST | 37,629.29 | 0.15% | 0.99% | 9.40% | 10.44% | 0.0155% |
| Republic Services Inc | RSG | 28,841.95 | 0.11% | 1.74% | 12.96% | 14.81% | 0.0169% |
| Raytheon Co | RTN | 49,631.97 | 0.20% | 2.11% | 8.38% | 10.57% | 0.0207% |
| SBA Communications Corp | SBAC | 29,440.25 | 0.12% | 0.20% | 46.90% | 47.15% | 0.0548% |
| Starbucks Corp | SBUX | 115,534.44 | 0.46% | 1.56% | 13.27% | 14.93% | 0.0681% |
| Charles Schwab Corp/The | SCHW | 48,548.78 | 0.19% | 1.81% | 4.21% | 6.06% | 0.0116% |
| Sealed Air Corp | SEE | 6,548.82 | 0.03% | 1.56% | 5.72% | 7.32% | 0.0019% |
| Sherwin-Williams Co/The | SHW | 48,904.17 | 0.19% | 0.83% | 11.83% | 12.71% | 0.0245% |
| SVB Financial Group | SIVB | 9,880.46 | 0.04% | 0.00% | 11.00% | 11.00% | 0.0043% |
| JM Smucker Co/The | SJM | 13,040.41 | 0.05% | 3.08% | 3.12% | 6.24% | 0.0032% |
| Schlumberger Ltd | SLB | 45,251.93 | 0.18% | 6.11% | 29.25% | 36.26% | 0.0648% |
| SL Green Realty Corp | SLG | 6,605.07 | 0.03% | 4.31% | -2.52% | 1.73% | 0.0005% |
| Snap-on Inc | SNA | 8,139.09 | 0.03% | 2.58% | 6.91% | 9.58% | 0.0031% |
| Synopsys Inc | SNPS | 19,333.99 | 0.08% | 0.00% | 13.60% | 13.60% | 0.0104% |
| Southern Co/The | SO | 62,062.98 | 0.25% | 4.29% | 3.75% | 8.12% | 0.0199% |
| Simon Property Group Inc | SPG | 45,775.08 | 0.18% | 5.59% | 5.15% | 10.89% | 0.0197% |
| S&P Global Inc | SPGI | 63,220.28 | 0.25% | 0.88% | 10.47% | 11.39% | 0.0284% |
| Sempra Energy | SRE | 38,110.53 | 0.15% | 2.80% | 9.43% | 12.36% | 0.0186% |
| SunTrust Banks Inc | STI | 26,938.16 | 0.11% | 3.49% | 2.37% | 5.90% | 0.0063% |
| State Street Corp | STT | 18,703.49 | 0.07% | 3.94% | 3.98% | 8.00% | 0.0059% |
| Seagate Technology PLC | STX | 12,383.81 | 0.05% | 5.47% | 5.74% | 11.37% | 0.0056% |
| Constellation Brands Inc | STZ | 37,959.14 | 0.15% | 1.51% | 7.74% | 9.31% | 0.0140% |
| Stanley Black & Decker Inc | SWK | 20,306.29 | 0.08% | 2.01% | 9.23% | 11.33% | 0.0091% |
| Skyworks Solutions Inc | SWKS | 13,162.76 | 0.05% | 2.05% | 12.93% | 15.11% | 0.0079% |
| Synchrony Financial | SYF | 22,178.80 | 0.09% | 2.61% | 6.70% | 9.39% | 0.0082% |
| Stryker Corp | SYK | 81,180.48 | 0.32% | 0.96% | 9.55% | 10.56% | 0.0338% |
| Symantec Corp | SYMC | 14,529.92 | 0.06% | 1.29% | 4.10% | 5.42% | 0.0031% |
| Sysco Corp | SYY | 37,499.64 | 0.15% | 2.29% | 11.13% | 13.55% | 0.0201% |
| AT&T Inc | T | 255,525.79 | 1.01% | 5.85% | 5.59% | 11.60% | 0.1170% |
| Molson Coors Brewing Co | TAP | 11,384.68 | 0.04% | 3.82% | -1.16% | 2.65% | 0.0012% |
| TransDigm Group Inc | TDG | 28,269.92 | 0.11% | 0.00% | 14.40% | 14.40% | 0.0161% |
| TE Connectivity Ltd | TEL | 30,230.81 | 0.12% | 1.99% | 9.43% | 11.51% | 0.0137% |
| Teleflex Inc | TFX | 17,097.37 | 0.07% | 0.37% | 12.90% | 13.29% | 0.0090% |
| Target Corp | TGT | 43,143.69 | 0.17% | 3.12% | 7.50% | 10.74% | 0.0183% |
| Tiffany & Co | TIF | 9,809.72 | 0.04% | 2.87% | 9.25% | 12.25% | 0.0047% |
| TJX Cos Inc/The | TJX | 62,318.99 | 0.25% | 1.79% | 11.07% | 12.96% | 0.0319% |
| Thermo Fisher Scientific Inc | TMO | 110,591.38 | 0.44% | 0.26% | 11.43% | 11.70% | 0.0511% |
| T-Mobile US Inc | TMUS | 66,434.04 | 0.26% | 0.00% | 6.53% | 6.53% | 0.0171% |
| Tapestry Inc | TPR | 5,725.52 | 0.02% | 6.82% | 8.77% | 15.88% | 0.0036% |
| TripAdvisor Inc | TRIP | 5,292.01 | 0.02% | 0.00% | 14.28% | 14.28% | 0.0030% |
| T Rowe Price Group Inc | TROW | 25,292.62 | 0.10% | 2.80% | 8.20% | 11.11% | 0.0111% |
| Travelers Cos Inc/The | TRV | 38,227.23 | 0.15% | 2.20% | 12.58% | 14.92% | 0.0225% |
| Tractor Supply Co | TSCO | 11,992.09 | 0.05% | 1.33% | 10.82% | 12.22% | 0.0058% |
| Tyson Foods Inc | TSN | 31,982.99 | 0.13% | 1.71% | 5.00% | 6.75% | 0.0085% |
| Total System Services Inc | TSS | 22,539.42 | 0.09% | 0.42% | 10.00% | 10.44% | 0.0093% |
| Take-Two Interactive Software Inc | TTWO | 14,396.25 | 0.06% | 0.00% | 8.80% | 8.80% | 0.0050% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Twitter Inc | TWTR | 31,369.06 | 0.12% | 0.00% | 31.80% | 31.80% | 0.0394% |
| Texas Instruments Inc | TXN | 114,667.20 | 0.45% | 2.55% | 9.70% | 12.37% | 0.0560% |
| Textron Inc | TXT | 10,208.28 | 0.04% | 0.17% | 11.86% | 12.04% | 0.0049% |
| Under Armour Inc | UAA | 7,958.43 | 0.03% | 0.00% | 30.97% | 30.97% | 0.0097% |
| United Airlines Holdings Inc | UAL | 21,309.07 | 0.08% | 0.00% | 12.93% | 12.93% | 0.0109% |
| UDR Inc | UDR | 13,757.73 | 0.05% | 2.92% | 6.77% | 9.78% | 0.0053% |
| Universal Health Services Inc | UHS | 13,038.83 | 0.05% | 0.30% | 8.08% | 8.38% | 0.0043% |
| Ulta Beauty Inc | ULTA | 18,825.15 | 0.07% | 0.00% | 21.00% | 21.00% | 0.0156% |
| UnitedHealth Group Inc | UNH | 232,835.65 | 0.92% | 1.68% | 12.28% | 14.06% | 0.1293% |
| Unum Group | UNM | 5,568.36 | 0.02% | 4.06% | 9.00% | 13.24% | 0.0029% |
| Union Pacific Corp | UNP | 117,128.07 | 0.46% | 2.16% | 12.90% | 15.20% | 0.0703% |
| United Parcel Service Inc | UPS | 99,008.68 | 0.39% | 3.33% | 8.93% | 12.41% | 0.0485% |
| United Rentals Inc | URI | 8,332.81 | 0.03% | 0.00% | 12.00% | 12.00% | 0.0039% |
| US Bancorp | USB | 82,384.22 | 0.33% | 3.02% | 6.33% | 9.45% | 0.0307% |
| United Technologies Corp | UTX | 107,897.05 | 0.43% | 2.37% | 9.75% | 12.23% | 0.0521% |
| Visa Inc | V | 353,593.14 | 1.40% | 0.56% | 15.71% | 16.31% | 0.2278% |
| Varian Medical Systems Inc | VAR | 9,921.07 | 0.04% | 0.00% | 8.00% | 8.00% | 0.0031% |
| VF Corp | VFC | 31,368.35 | 0.12% | 2.20% | 10.74% | 13.05% | 0.0162% |
| Viacom Inc | VIAB | 10,559.12 | 0.04% | 3.09% | 3.36% | 6.51% | 0.0027% |
| Valero Energy Corp | VLO | 32,373.20 | 0.13% | 4.62% | 9.69% | 14.53% | 0.0186% |
| Vulcan Materials Co | VMC | 18,749.02 | 0.07% | 0.87% | 18.12% | 19.06% | 0.0141% |
| Vornado Realty Trust | VNO | 11,687.33 | 0.05% | 4.25% | -0.99% | 3.24% | 0.0015% |
| Verisk Analytics Inc | VRSK | 25,650.83 | 0.10% | 0.45% | 9.47% | 9.95% | 0.0101% |
| VeriSign Inc | VRSN | 24,266.23 | 0.10% | 0.00% | 9.70% | 9.70% | 0.0093% |
| Vertex Pharmaceuticals Inc | VRTX | 47,536.13 | 0.19% | 0.00% | 43.73% | 43.73% | 0.0821% |
| Ventas Inc | VTR | 27,273.19 | 0.11% | 4.34% | 5.00% | 9.45% | 0.0102% |
| Verizon Communications Inc | VZ | 234,291.08 | 0.93% | 4.30% | 2.56% | 6.92% | 0.0640% |
| Wabtec Corp | WAB | 12,770.96 | 0.05% | 0.76% | 76.00% | 77.05% | 0.0389% |
| Waters Corp | WAT | 13,721.74 | 0.05% | 0.00% | 11.26% | 11.26% | 0.0061% |
| Walgreens Boots Alliance Inc | WBA | 45,590.68 | 0.18% | 3.55% | 5.47% | 9.12% | 0.0164% |
| WellCare Health Plans Inc | WCG | 13,803.62 | 0.05% | 0.00% | 15.83% | 15.83% | 0.0086% |
| Western Digital Corp | WDC | 16,170.54 | 0.06% | 3.65% | 3.07% | 6.77% | 0.0043% |
| WEC Energy Group Inc | WEC | 28,528.02 | 0.11% | 2.61% | 6.20% | 8.89% | 0.0100% |
| Welltower Inc | WELL | 35,981.86 | 0.14% | 3.93% | 6.32% | 10.37% | 0.0147% |
| Wells Fargo & Co | WFC | 195,587.09 | 0.77% | 4.31% | 9.86% | 14.38% | 0.1110% |
| Whirlpool Corp | WHR | 8,371.01 | 0.03% | 3.62% | 4.61% | 8.32% | 0.0027% |
| Willis Towers Watson PLC | WLTW | 25,095.87 | 0.10% | 1.23% | 13.97% | 15.29% | 0.0151% |
| Waste Management Inc | WM | 50,534.54 | 0.20% | 1.72% | 7.74% | 9.53% | 0.0190% |
| Williams Cos Inc/The | WMB | 28,215.88 | 0.11% | 6.52% | 8.00% | 14.79% | 0.0165% |
| Walmart Inc | WMT | 322,555.05 | 1.27% | 1.88% | 4.96% | 6.89% | 0.0878% |
| Westrock Co | WRK | 8,582.34 | 0.03% | 5.42% | 1.80% | 7.27% | 0.0025% |
| Western Union Co/The | WU | 8,939.86 | 0.04% | 3.69% | 3.18% | 6.93% | 0.0024% |
| Weyerhaeuser Co | WY | 18,742.43 | 0.07% | 5.41% | 4.50% | 10.04% | 0.0074% |
| Wynn Resorts Ltd | WYNN | 11,358.86 | 0.04% | 3.60% | 11.50% | 15.30% | 0.0069% |
| Cimarex Energy Co | XEC | 4,164.81 | 0.02% | 1.76% | 26.17% | 28.15% | 0.0046% |
| Xcel Energy Inc | XEL | 31,827.66 | 0.13% | 2.62% | 5.59% | 8.29% | 0.0104% |
| Xilinx Inc | XLNX | 26,639.70 | 0.11% | 1.41% | 9.45% | 10.92% | 0.0115% |
| Exxon Mobil Corp | XOM | 288,984.56 | 1.14% | 5.01% | 8.27% | 13.49% | 0.1539% |
| DENTSPLY SIRONA Inc | XRAY | 11,731.52 | 0.05% | 0.68% | 13.14% | 13.87% | 0.0064% |
| Xerox Holdings Corp | XRX | 6,307.88 | 0.02% | 3.55% | 6.20% | 9.86% | 0.0025% |
| Xylem Inc/NY | XYL | 13,784.83 | 0.05% | 1.26% | 14.65% | 16.00% | 0.0087% |
| Yum! Brands Inc | YUM | 35,181.52 | 0.14% | 1.45% | 12.50% | 14.04% | 0.0195% |
| Zimmer Biomet Holdings Inc | ZBH | 28,130.14 | 0.11% | 0.72% | 6.22% | 6.96% | 0.0077% |
| Zions Bancorp NA | ZION | 7,113.91 | 0.03% | 3.21% | 6.24% | 9.55% | 0.0027% |
| Zoetis Inc | ZTS | 59,871.44 | 0.24% | 0.50% | 10.23% | 10.75% | 0.0254% |
| | Total Market Capitalization: | 25,326,454.83 | | | | | 14.48% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 14.62% | 2.43% | 12.19% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 22,047.51 | 0.09% | 0.95% | 9.50% | 10.50% | 0.0097% |
| American Airlines Group Inc | AAL | 12,948.22 | 0.05% | 1.38% | 6.50% | 7.92% | 0.0043% |
| Advance Auto Parts Inc | AAP | 10,360.97 | 0.04% | 0.17% | 14.00% | 14.18% | 0.0061% |
| Apple Inc | AAPL | 921,821.60 | 3.85% | 1.54% | 12.50% | 14.14% | 0.5443% |
| AbbVie Inc | ABBV | 103,295.70 | 0.43% | 6.54% | 10.50% | 17.38% | 0.0750% |
| AmerisourceBergen Corp | ABC | 18,471.58 | 0.08% | 1.89% | 8.00% | 9.97% | 0.0077% |
| ABIOMED Inc | ABMD | 8,650.08 | 0.04% | 0.00% | 15.00% | 15.00% | 0.0054% |
| Abbott Laboratories | ABT | 151,218.60 | 0.63% | 1.50% | 10.00% | 11.58% | 0.0731% |
| Accenture PLC | ACN | 123,854.40 | 0.52% | 1.65% | 9.00% | 10.72% | 0.0555% |
| Adobe Inc | ADBE | 144,802.40 | 0.60% | 0.00% | 20.50% | 20.50% | 0.1240% |
| Analog Devices Inc | ADI | 41,535.25 | 0.17% | 1.92% | 10.00% | 12.02% | 0.0208% |
| Archer-Daniels-Midland Co | ADM | 21,371.40 | 0.09% | 3.66% | 9.50% | 13.33% | 0.0119% |
| Automatic Data Processing Inc | ADP | 74,174.36 | 0.31% | 2.03% | 14.50% | 16.68% | 0.0517% |
| Alliance Data Systems Corp | ADS | 8,121.14 | 0.03% | 1.62% | 12.00% | 13.72% | 0.0047% |
| Autodesk Inc | ADSK | 33,402.00 | N/A | 0.00% | N/A | N/A | N/A |
| Ameren Corp | AEE | 18,759.46 | 0.08% | 2.61% | 6.50% | 9.19% | 0.0072% |
| American Electric Power Co Inc | AEP | 44,196.28 | 0.18% | 3.13% | 4.00% | 7.19% | 0.0133% |
| AES Corp/VA | AES | 10,521.20 | N/A | 3.47% | N/A | N/A | N/A |
| Aflac Inc | AFL | 39,474.23 | 0.16% | 2.08% | 7.50% | 9.66% | 0.0159% |
| Allergan PLC | AGN | 52,398.83 | 0.22% | 1.85% | 3.50% | 5.38% | 0.0118% |
| American International Group Inc | AIG | 49,418.46 | N/A | 2.25% | N/A | N/A | N/A |
| Apartment Investment & Management Co | AIV | 7,732.19 | 0.03% | 3.08% | -3.00% | 0.03% | 0.0000% |
| Assurant Inc | AIZ | 7,368.17 | 0.03% | 2.01% | 6.50% | 8.58% | 0.0026% |
| Arthur J Gallagher & Co | AJG | 16,783.51 | 0.07% | 1.91% | 14.50% | 16.55% | 0.0116% |
| Akamai Technologies Inc | AKAM | 14,524.25 | 0.06% | 0.00% | 18.00% | 18.00% | 0.0109% |
| Albemarle Corp | ALB | 7,787.81 | 0.03% | 2.00% | 5.50% | 7.56% | 0.0025% |
| Align Technology Inc | ALGN | 15,062.40 | 0.06% | 0.00% | 25.00% | 25.00% | 0.0157% |
| Alaska Air Group Inc | ALK | 7,959.00 | 0.03% | 2.17% | 5.50% | 7.73% | 0.0026% |
| Allstate Corp/The | ALL | 35,064.90 | 0.15% | 1.90% | 10.50% | 12.50% | 0.0183% |
| Allegion PLC | ALLE | 9,265.67 | 0.04% | 1.09% | 8.50% | 9.64% | 0.0037% |
| Alexion Pharmaceuticals Inc | ALXN | 25,135.06 | 0.10% | 0.00% | 26.00% | 26.00% | 0.0273% |
| Applied Materials Inc | AMAT | 44,796.96 | 0.19% | 1.78% | 8.50% | 10.36% | 0.0194% |
| Amcor PLC | AMCR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Advanced Micro Devices Inc | AMD | 37,006.72 | 0.15% | 0.00% | 27.50% | 27.50% | 0.0425% |
| AMETEK Inc | AME | 19,850.12 | 0.08% | 0.64% | 15.50% | 16.19% | 0.0134% |
| Affiliated Managers Group Inc | AMG | 4,112.78 | 0.02% | 1.65% | 10.00% | 11.73% | 0.0020% |
| Amgen Inc | AMGN | 111,527.00 | 0.47% | 3.19% | 7.00% | 10.30% | 0.0480% |
| Ameriprise Financial Inc | AMP | 17,716.68 | 0.07% | 2.88% | 12.50% | 15.56% | 0.0115% |
| American Tower Corp | AMT | 97,776.15 | 0.41% | 1.85% | 9.50% | 11.44% | 0.0467% |
| Amazon.com Inc | AMZN | 905,447.60 | 3.78% | 0.00% | 39.00% | 39.00% | 1.4749% |
| Arista Networks Inc | ANET | 17,951.38 | 0.07% | 0.00% | 11.50% | 11.50% | 0.0086% |
| ANSYS Inc | ANSS | 17,759.96 | 0.07% | 0.00% | 11.50% | 11.50% | 0.0085% |
| Anthem Inc | ANTM | 73,858.62 | 0.31% | 1.11% | 19.00% | 20.22% | 0.0624% |
| Aon PLC | AON | 44,712.29 | 0.19% | 0.93% | 10.00% | 10.98% | 0.0205% |
| AO Smith Corp | AOS | 7,547.74 | 0.03% | 1.92% | 9.50% | 11.51% | 0.0036% |
| Apache Corp | APA | 8,440.21 | 0.04% | 4.45% | 50.00% | 55.56% | 0.0196% |
| Air Products & Chemicals Inc | APD | 50,236.54 | 0.21% | 2.04% | 9.50% | 11.64% | 0.0244% |
| Amphenol Corp | APH | 26,395.54 | 0.11% | 1.13% | 9.50% | 10.68% | 0.0118% |
| Aptiv PLC | APTV | 21,894.26 | 0.09% | 1.03% | 11.00% | 12.09% | 0.0111% |
| Alexandria Real Estate Equities Inc | ARE | 16,257.71 | N/A | 2.73% | N/A | N/A | N/A |
| Arconic Inc | ARNC | 11,193.98 | N/A | 0.32% | N/A | N/A | N/A |
| Atmos Energy Corp | ATO | 12,801.45 | 0.05% | 2.02% | 7.50% | 9.60% | 0.0051% |
| Activision Blizzard Inc | ATVI | 37,828.27 | 0.16% | 0.81% | 9.50% | 10.35% | 0.0164% |
| AvalonBay Communities Inc | AVB | 28,604.67 | 0.12% | 3.03% | 2.50% | 5.57% | 0.0067% |
| Broadcom Inc | AVGO | 108,121.00 | 0.45% | 3.91% | 33.50% | 38.06% | 0.1719% |
| Avery Dennison Corp | AVY | 9,658.31 | 0.04% | 2.08% | 11.00% | 13.19% | 0.0053% |
| American Water Works Co Inc | AWK | 21,571.66 | 0.09% | 1.72% | 9.50% | 11.30% | 0.0102% |
| American Express Co | AXP | 104,241.30 | 0.44% | 1.37% | 10.00% | 11.44% | 0.0498% |
| AutoZone Inc | AZO | 26,780.95 | 0.11% | 0.00% | 13.50% | 13.50% | 0.0151% |
| Boeing Co/The | BA | 189,265.10 | 0.79% | 2.59% | 15.50% | 18.29% | 0.1446% |
| Bank of America Corp | BAC | 271,550.90 | 1.13% | 2.54% | 10.50% | 13.17% | 0.1494% |
| Baxter International Inc | BAX | 43,746.18 | 0.18% | 1.03% | 10.50% | 11.58% | 0.0212% |
| BB&T Corp | BBT | 36,377.81 | 0.15% | 3.79% | 8.00% | 11.94% | 0.0181% |
| Best Buy Co Inc | BBY | 18,398.97 | 0.08% | 3.05% | 8.50% | 11.68% | 0.0090% |
| Becton Dickinson and Co | BDX | 67,912.33 | 0.28% | 1.25% | 10.00% | 11.31% | 0.0321% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Franklin Resources Inc | BEN | 15,410.95 | 0.06% | 3.70% | 7.50% | 11.34% | 0.0073% |
| Brown-Forman Corp | BF/B | 26,621.43 | 0.11% | 1.20% | 14.50% | 15.79% | 0.0176% |
| Baker Hughes a GE Co | BHGE | 12,432.10 | N/A | 2.98% | N/A | N/A | N/A |
| Biogen Inc | BIIB | 49,694.78 | 0.21% | 0.00% | 4.50% | 4.50% | 0.0093% |
| Bank of New York Mellon Corp/The | BK | 42,957.11 | 0.18% | 2.72% | 7.00% | 9.82% | 0.0176% |
| Booking Holdings Inc | BKNG | 85,765.47 | 0.36% | 0.00% | 12.00% | 12.00% | 0.0430% |
| BlackRock Inc | BLK | 67,631.55 | 0.28% | 3.02% | 9.00% | 12.16% | 0.0343% |
| Ball Corp | BLL | 25,246.39 | 0.11% | 0.79% | 23.00% | 23.88% | 0.0252% |
| Bristol-Myers Squibb Co | BMY | 77,355.42 | 0.32% | 3.47% | 8.00% | 11.61% | 0.0375% |
| Broadridge Financial Solutions Inc | BR | 14,617.43 | 0.06% | 1.71% | 11.00% | 12.80% | 0.0078% |
| Berkshire Hathaway Inc | BRK/B | - | N/A | 0.00% | N/A | N/A | N/A |
| Boston Scientific Corp | BSX | 59,461.33 | 0.25% | 0.00% | 16.00% | 16.00% | 0.0397% |
| BorgWarner Inc | BWA | 7,223.90 | 0.03% | 1.94% | 7.00% | 9.01% | 0.0027% |
| Boston Properties Inc | BXP | 20,218.55 | 0.08% | 2.98% | 5.00% | 8.05% | 0.0068% |
| Citigroup Inc | C | 150,769.40 | 0.63% | 3.06% | 10.00% | 13.21% | 0.0832% |
| Conagra Brands Inc | CAG | 13,702.80 | 0.06% | 3.01% | 4.50% | 7.58% | 0.0043% |
| Cardinal Health Inc | CAH | 13,079.22 | 0.05% | 4.38% | 17.00% | 21.75% | 0.0119% |
| Caterpillar Inc | CAT | 68,647.11 | 0.29% | 3.38% | 13.00% | 16.60% | 0.0476% |
| Chubb Ltd | CB | 72,291.48 | 0.30% | 1.90% | 10.00% | 12.00% | 0.0362% |
| Cboe Global Markets Inc | CBOE | 13,272.74 | 0.06% | 1.21% | 14.50% | 15.80% | 0.0088% |
| CBRE Group Inc | CBRE | 17,852.36 | 0.07% | 0.00% | 10.50% | 10.50% | 0.0078% |
| CBS Corp | CBS | 19,057.50 | 0.08% | 1.54% | 9.50% | 11.11% | 0.0088% |
| Crown Castle International Corp | CCI | 58,631.04 | 0.24% | 3.41% | 10.50% | 14.09% | 0.0345% |
| Carnival Corp | CCL | 24,479.15 | 0.10% | 4.31% | 10.00% | 14.53% | 0.0149% |
| Cadence Design Systems Inc | CDNS | 20,000.12 | 0.08% | 0.00% | 12.50% | 12.50% | 0.0104% |
| Celanese Corp | CE | 13,504.98 | 0.06% | 2.27% | 8.50% | 10.87% | 0.0061% |
| Celgene Corp | CELG | 67,160.39 | 0.28% | 0.00% | 9.00% | 9.00% | 0.0252% |
| Cerner Corp | CERN | 22,739.97 | 0.09% | 1.01% | 9.00% | 10.06% | 0.0096% |
| CF Industries Holdings Inc | CF | 11,416.63 | N/A | 2.40% | N/A | N/A | N/A |
| Citizens Financial Group Inc | CFG | 15,339.78 | 0.06% | 4.30% | 9.50% | 14.00% | 0.0090% |
| Church & Dwight Co Inc | CHD | 19,065.31 | 0.08% | 1.18% | 9.00% | 10.23% | 0.0081% |
| CH Robinson Worldwide Inc | CHRW | 11,681.01 | 0.05% | 2.32% | 9.00% | 11.42% | 0.0056% |
| Charter Communications Inc | CHTR | 84,168.29 | 0.35% | 0.00% | 16.00% | 16.00% | 0.0562% |
| Cigna Corp | CI | 63,217.54 | 0.26% | 0.02% | 14.50% | 14.52% | 0.0383% |
| Cincinnati Financial Corp | CINF | 17,909.57 | 0.07% | 2.04% | 8.50% | 10.63% | 0.0079% |
| Colgate-Palmolive Co | CL | 61,527.62 | 0.26% | 2.40% | 6.00% | 8.47% | 0.0218% |
| Clorox Co/The | CLX | 20,331.64 | 0.08% | 2.67% | 6.50% | 9.26% | 0.0079% |
| Comerica Inc | CMA | 9,470.17 | 0.04% | 4.24% | 12.00% | 16.49% | 0.0065% |
| Comcast Corp | CMCSA | 193,889.10 | 0.81% | 1.97% | 13.50% | 15.60% | 0.1264% |
| CME Group Inc | CME | 75,366.08 | 0.31% | 1.42% | 3.00% | 4.44% | 0.0140% |
| Chipotle Mexican Grill Inc | CMG | 22,568.72 | 0.09% | 0.00% | 26.00% | 26.00% | 0.0245% |
| Cummins Inc | CMI | 24,257.02 | 0.10% | 3.41% | 8.00% | 11.55% | 0.0117% |
| CMS Energy Corp | CMS | 17,047.87 | 0.07% | 2.65% | 7.00% | 9.74% | 0.0069% |
| Centene Corp | CNC | 20,448.91 | 0.09% | 0.00% | 15.50% | 15.50% | 0.0132% |
| CenterPoint Energy Inc | CNP | 13,975.34 | 0.06% | 4.20% | 12.50% | 16.96% | 0.0099% |
| Capital One Financial Corp | COF | 41,746.75 | 0.17% | 1.80% | 6.00% | 7.85% | 0.0137% |
| Cabot Oil & Gas Corp | COG | 7,392.92 | 0.03% | 2.04% | 50.00% | 52.55% | 0.0162% |
| Cooper Cos Inc/The | COO | 16,539.93 | 0.07% | 0.02% | 14.50% | 14.52% | 0.0100% |
| ConocoPhillips | COP | 61,135.52 | 0.26% | 2.22% | 37.00% | 39.63% | 0.1012% |
| Costco Wholesale Corp | COST | 120,860.10 | 0.50% | 0.95% | 8.50% | 9.49% | 0.0479% |
| Coty Inc | COTY | 7,829.59 | 0.03% | 4.80% | 9.00% | 14.02% | 0.0046% |
| Campbell Soup Co | CPB | 12,651.03 | 0.05% | 3.33% | 0.50% | 3.84% | 0.0020% |
| Capri Holdings Ltd | CPRI | 4,933.97 | 0.02% | 0.00% | 10.50% | 10.50% | 0.0022% |
| Copart Inc | CPRT | 17,307.49 | 0.07% | 0.00% | 17.50% | 17.50% | 0.0127% |
| salesforce.com Inc | CRM | 111,604.30 | 0.47% | 0.00% | 29.00% | 29.00% | 0.1352% |
| Cisco Systems Inc | CSCO | 229,279.10 | 0.96% | 2.63% | 8.00% | 10.74% | 0.1028% |
| CSX Corp | CSX | 53,270.27 | 0.22% | 1.44% | 14.50% | 16.04% | 0.0357% |
| Cintas Corp | CTAS | 27,296.93 | 0.11% | 0.85% | 16.00% | 16.92% | 0.0193% |
| CenturyLink Inc | CTL | 11,664.47 | 0.05% | 9.35% | 1.00% | 10.40% | 0.0051% |
| Cognizant Technology Solutions Corp | CTSH | 35,305.92 | 0.15% | 1.25% | 6.00% | 7.29% | 0.0107% |
| Corteva Inc | CTVA | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Citrix Systems Inc | CTXS | 12,059.24 | 0.05% | 1.52% | 6.50% | 8.07% | 0.0041% |
| CVS Health Corp | CVS | 76,692.96 | 0.32% | 3.39% | 6.50% | 10.00% | 0.0320% |
| Chevron Corp | CVX | 234,719.40 | 0.98% | 3.86% | 16.50% | 20.68% | 0.2027% |
| Concho Resources Inc | CXO | 14,726.05 | 0.06% | 0.68% | 21.00% | 21.75% | 0.0134% |
| Dominion Energy Inc | D | 60,489.99 | 0.25% | 4.94% | 6.50% | 11.60% | 0.0293% |
| Delta Air Lines Inc | DAL | 39,031.57 | 0.16% | 2.68% | 9.50% | 12.31% | 0.0201% |
| DuPont de Nemours Inc | DD | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Deere & Co | DE | 49,153.40 | 0.21% | 1.96% | 14.00% | 16.10% | 0.0330% |
| Discover Financial Services | DFS | 27,037.17 | 0.11% | 2.08% | 7.50% | 9.66% | 0.0109% |
| Dollar General Corp | DG | 35,491.00 | 0.15% | 0.93% | 12.00% | 12.99% | 0.0192% |
| Quest Diagnostics Inc | DGX | 13,666.05 | 0.06% | 2.09% | 8.50% | 10.68% | 0.0061% |
| DR Horton Inc | DHI | 17,718.32 | 0.07% | 1.27% | 6.50% | 7.81% | 0.0058% |
| Danaher Corp | DHR | 100,849.10 | 0.42% | 0.48% | 13.50% | 14.01% | 0.0590% |
| Walt Disney Co/The | DIS | 245,582.10 | 1.03% | 1.28% | 6.50% | 7.82% | 0.0802% |
| Discovery Inc | DISCA | 15,547.08 | 0.06% | 0.00% | 18.00% | 18.00% | 0.0117% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| DISH Network Corp | DISH | 15,442.92 | 0.06% | 0.00% | -2.00% | -2.00% | -0.0013% |
| Digital Realty Trust Inc | DLR | 24,717.45 | 0.10% | 3.74% | 7.00% | 10.87% | 0.0112% |
| Dollar Tree Inc | DLTR | 22,077.79 | 0.09% | 0.00% | 11.50% | 11.50% | 0.0106% |
| Dover Corp | DOV | 13,441.38 | 0.06% | 2.12% | 10.50% | 12.73% | 0.0071% |
| Dow Inc | DOW | 34,774.89 | N/A | 6.09% | N/A | N/A | N/A |
| Duke Realty Corp | DRE | 11,953.33 | 0.05% | 2.73% | 4.50% | 7.29% | 0.0036% |
| Darden Restaurants Inc | DRI | 15,009.22 | 0.06% | 2.88% | 12.00% | 15.05% | 0.0094% |
| DTE Energy Co | DTE | 23,699.12 | 0.10% | 3.06% | 5.50% | 8.64% | 0.0086% |
| Duke Energy Corp | DUK | 65,017.68 | 0.27% | 4.26% | 6.00% | 10.39% | 0.0282% |
| DaVita Inc | DVA | 9,833.84 | 0.04% | 0.00% | 11.00% | 11.00% | 0.0045% |
| Devon Energy Corp | DVN | 10,003.29 | 0.04% | 1.47% | 26.50% | 28.16% | 0.0118% |
| DXC Technology Co | DXC | 13,864.15 | 0.06% | 1.63% | 10.00% | 11.71% | 0.0068% |
| Electronic Arts Inc | EA | 28,188.08 | 0.12% | 0.00% | 11.00% | 11.00% | 0.0130% |
| eBay Inc | EBAY | 34,732.50 | 0.15% | 1.41% | 10.00% | 11.48% | 0.0167% |
| Ecolab Inc | ECL | 59,000.67 | 0.25% | 0.90% | 10.00% | 10.95% | 0.0270% |
| Consolidated Edison Inc | ED | 29,059.96 | 0.12% | 3.47% | 3.00% | 6.52% | 0.0079% |
| Equifax Inc | EFX | 17,410.81 | 0.07% | 1.08% | 8.00% | 9.12% | 0.0066% |
| Edison International | EIX | 24,474.92 | 0.10% | 3.26% | 14.00% | 17.49% | 0.0179% |
| Estee Lauder Cos Inc/The | EL | 67,445.34 | 0.28% | 0.93% | 12.50% | 13.49% | 0.0380% |
| Eastman Chemical Co | EMN | 9,373.75 | 0.04% | 3.62% | 8.00% | 11.76% | 0.0046% |
| Emerson Electric Co | EMR | 37,379.63 | 0.16% | 3.24% | 12.00% | 15.43% | 0.0241% |
| EOG Resources Inc | EOG | 46,634.11 | 0.19% | 1.43% | 34.50% | 36.18% | 0.0705% |
| Equinix Inc | EQIX | 46,585.99 | 0.19% | 1.86% | 22.00% | 24.06% | 0.0468% |
| Equity Residential | EQR | 29,862.70 | 0.12% | 2.86% | -13.50% | -10.83% | -0.0135% |
| Eversource Energy | ES | 25,371.44 | 0.11% | 2.81% | 5.50% | 8.39% | 0.0089% |
| Essex Property Trust Inc | ESS | 20,044.40 | 0.08% | 2.62% | -0.50% | 2.11% | 0.0018% |
| E*TRADE Financial Corp | ETFC | 10,571.20 | 0.04% | 1.30% | 17.50% | 18.91% | 0.0084% |
| Eaton Corp PLC | ETN | 33,499.20 | 0.14% | 3.56% | 9.00% | 12.72% | 0.0178% |
| Entergy Corp | ETR | 21,267.35 | 0.09% | 3.46% | 0.50% | 3.97% | 0.0035% |
| Evergy Inc | EVRG | 14,582.41 | N/A | 3.25% | N/A | N/A | N/A |
| Edwards Lifesciences Corp | EW | 45,135.09 | 0.19% | 0.00% | 15.50% | 15.50% | 0.0292% |
| Exelon Corp | EXC | 44,057.40 | 0.18% | 3.33% | 9.00% | 12.48% | 0.0230% |
| Expeditors International of Washington I | EXPD | 12,436.72 | 0.05% | 1.37% | 7.50% | 8.92% | 0.0046% |
| Expedia Group Inc | EXPE | 19,405.85 | 0.08% | 1.04% | 24.00% | 25.16% | 0.0204% |
| Extra Space Storage Inc | EXR | 15,088.52 | 0.06% | 3.07% | 4.00% | 7.13% | 0.0045% |
| Ford Motor Co | F | 38,142.90 | 0.16% | 6.28% | 3.50% | 9.89% | 0.0158% |
| Diamondback Energy Inc | FANG | 15,671.35 | 0.07% | 0.79% | 17.00% | 17.86% | 0.0117% |
| Fastenal Co | FAST | 17,052.83 | 0.07% | 2.96% | 8.50% | 11.59% | 0.0083% |
| Facebook Inc | FB | 542,716.60 | 2.27% | 0.00% | 17.50% | 17.50% | 0.3967% |
| Fortune Brands Home & Security Inc | FBHS | 7,426.61 | 0.03% | 1.66% | 10.50% | 12.25% | 0.0038% |
| Freeport-McMoRan Inc | FCX | 14,684.12 | 0.06% | 1.98% | 22.50% | 24.70% | 0.0152% |
| FedEx Corp | FDX | 42,794.23 | 0.18% | 1.74% | 7.50% | 9.31% | 0.0166% |
| FirstEnergy Corp | FE | 23,516.31 | 0.10% | 3.57% | 8.00% | 11.71% | 0.0115% |
| F5 Networks Inc | FFIV | 8,262.33 | 0.03% | 0.00% | 12.00% | 12.00% | 0.0041% |
| Fidelity National Information Services I | FIS | 44,190.36 | 0.18% | 1.03% | 18.00% | 19.12% | 0.0353% |
| Fiserv Inc | FISV | 41,423.45 | 0.17% | 0.00% | 10.50% | 10.50% | 0.0182% |
| Fifth Third Bancorp | FITB | 19,632.76 | 0.08% | 3.58% | 7.00% | 10.71% | 0.0088% |
| FLIR Systems Inc | FLIR | 6,604.93 | 0.03% | 1.44% | 12.00% | 13.53% | 0.0037% |
| Flowserve Corp | FLS | 5,905.26 | 0.02% | 1.68% | 13.50% | 15.29% | 0.0038% |
| FleetCor Technologies Inc | FLT | 25,543.83 | 0.11% | 0.00% | 16.50% | 16.50% | 0.0176% |
| FMC Corp | FMC | 11,581.14 | 0.05% | 1.92% | 15.00% | 17.06% | 0.0083% |
| Fox Corp | FOXA | N/A | N/A | 0.00% | N/A | N/A | N/A |
| First Republic Bank/CA | FRC | 15,641.20 | 0.07% | 0.81% | 10.50% | 11.35% | 0.0074% |
| Federal Realty Investment Trust | FRT | 9,762.39 | 0.04% | 3.19% | 3.00% | 6.24% | 0.0025% |
| TechnipFMC PLC | FTI | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Fortinet Inc | FTNT | 14,427.27 | 0.06% | 0.00% | 26.00% | 26.00% | 0.0157% |
| Fortive Corp | FTV | 24,095.13 | 0.10% | 0.39% | 10.00% | 10.41% | 0.0105% |
| General Dynamics Corp | GD | 53,196.40 | 0.22% | 2.22% | 6.00% | 8.29% | 0.0184% |
| General Electric Co | GE | 82,760.47 | 0.35% | 0.42% | 2.50% | 2.93% | 0.0101% |
| Gilead Sciences Inc | GILD | 82,580.69 | 0.34% | 3.89% | -1.50% | 2.36% | 0.0081% |
| General Mills Inc | GIS | 32,514.64 | 0.14% | 3.67% | 4.00% | 7.74% | 0.0105% |
| Globe Life Inc | GL | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Corning Inc | GLW | 22,795.30 | 0.10% | 2.74% | 15.00% | 17.95% | 0.0171% |
| General Motors Co | GM | 57,251.93 | 0.24% | 3.89% | 2.50% | 6.44% | 0.0154% |
| Alphabet Inc | GOOGL | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Genuine Parts Co | GPC | 13,426.03 | 0.06% | 3.32% | 8.50% | 11.96% | 0.0067% |
| Global Payments Inc | GPN | 25,127.54 | 0.10% | 0.03% | 17.50% | 17.53% | 0.0184% |
| Gap Inc/The | GPS | 6,879.60 | 0.03% | 5.33% | 5.00% | 10.46% | 0.0030% |
| Garmin Ltd | GRMN | 14,951.52 | 0.06% | 2.90% | 10.00% | 13.05% | 0.0081% |
| Goldman Sachs Group Inc/The | GS | 75,921.59 | 0.32% | 2.42% | 8.50% | 11.02% | 0.0350% |
| WW Grainger Inc | GWW | 15,098.70 | 0.06% | 2.08% | 8.50% | 10.67% | 0.0067% |
| Halliburton Co | HAL | 17,418.82 | 0.07% | 3.61% | 24.50% | 28.55% | 0.0208% |
| Hasbro Inc | HAS | 14,720.78 | 0.06% | 2.33% | 8.00% | 10.42% | 0.0064% |
| Huntington Bancshares Inc/OH | HBAN | 13,491.93 | 0.06% | 4.62% | 11.50% | 16.39% | 0.0092% |
| Hanesbrands Inc | HBI | 5,419.35 | 0.02% | 4.00% | 4.00% | 8.08% | 0.0018% |
| HCA Healthcare Inc | HCA | 43,434.59 | 0.18% | 1.26% | 12.50% | 13.84% | 0.0251% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| HCP Inc | HCP | 16,335.14 | 0.07% | 4.33% | -3.50% | 0.75% | 0.0005% |
| Home Depot Inc/The | HD | 232,938.60 | 0.97% | 2.57% | 9.00% | 11.69% | 0.1137% |
| Hess Corp | HES | 18,375.43 | N/A | 1.66% | N/A | N/A | N/A |
| HollyFrontier Corp | HFC | 8,467.49 | 0.04% | 2.70% | 18.50% | 21.45% | 0.0076% |
| Hartford Financial Services Group Inc/Th | HIG | 21,182.77 | 0.09% | 2.08% | 12.50% | 14.71% | 0.0130% |
| Huntington Ingalls Industries Inc | HII | 8,781.77 | 0.04% | 1.62% | 7.00% | 8.68% | 0.0032% |
| Hilton Worldwide Holdings Inc | HLT | 27,552.36 | 0.12% | 0.63% | 17.00% | 17.68% | 0.0203% |
| Harley-Davidson Inc | HOG | 5,383.74 | 0.02% | 4.37% | 8.50% | 13.06% | 0.0029% |
| Hologic Inc | HOLX | 13,368.62 | 0.06% | 0.00% | 12.00% | 12.00% | 0.0067% |
| Honeywell International Inc | HON | 120,165.00 | 0.50% | 1.96% | 8.50% | 10.54% | 0.0529% |
| Helmerich & Payne Inc | HP | 4,810.68 | N/A | 6.46% | N/A | N/A | N/A |
| Hewlett Packard Enterprise Co | HPE | 18,241.44 | 0.08% | 3.62% | 6.50% | 10.24% | 0.0078% |
| HP Inc | HPQ | 29,412.18 | 0.12% | 3.43% | 8.50% | 12.08% | 0.0148% |
| H&R Block Inc | HRB | 5,594.26 | 0.02% | 3.79% | 7.00% | 10.92% | 0.0026% |
| Hormel Foods Corp | HRL | 22,397.96 | 0.09% | 2.11% | 9.00% | 11.20% | 0.0105% |
| Henry Schein Inc | HSIC | 9,250.83 | 0.04% | 0.00% | 7.00% | 7.00% | 0.0027% |
| Host Hotels & Resorts Inc | HST | 12,438.72 | 0.05% | 4.82% | 0.50% | 5.33% | 0.0028% |
| Hershey Co/The | HSY | 32,406.99 | 0.14% | 2.00% | 6.50% | 8.57% | 0.0116% |
| Humana Inc | HUM | 39,869.09 | 0.17% | 0.75% | 11.50% | 12.29% | 0.0205% |
| International Business Machines Corp | IBM | 124,218.70 | 0.52% | 4.65% | 2.00% | 6.70% | 0.0347% |
| Intercontinental Exchange Inc | ICE | 51,561.51 | 0.22% | 1.20% | 10.50% | 11.76% | 0.0253% |
| IDEXX Laboratories Inc | IDXX | 23,727.40 | 0.10% | 0.00% | 13.00% | 13.00% | 0.0129% |
| IDEX Corp | IEX | 12,295.83 | 0.05% | 1.23% | 9.50% | 10.79% | 0.0055% |
| International Flavors & Fragrances Inc | IFF | 13,031.77 | 0.05% | 2.52% | 8.50% | 11.13% | 0.0061% |
| Illumina Inc | ILMN | 43,870.68 | 0.18% | 0.00% | 14.00% | 14.00% | 0.0257% |
| Incyte Corp | INCY | 17,460.01 | N/A | 0.00% | N/A | N/A | N/A |
| IHS Markit Ltd | INFO | 25,569.27 | 0.11% | 0.00% | 17.00% | 17.00% | 0.0182% |
| Intel Corp | INTC | 208,963.10 | 0.87% | 2.67% | 10.50% | 13.31% | 0.1162% |
| Intuit Inc | INTU | 71,757.72 | 0.30% | 0.74% | 13.50% | 14.29% | 0.0428% |
| International Paper Co | IP | 16,130.20 | 0.07% | 4.88% | 11.50% | 16.66% | 0.0112% |
| Interpublic Group of Cos Inc/The | IPG | 8,296.01 | 0.03% | 4.66% | 11.00% | 15.92% | 0.0055% |
| IPG Photonics Corp | IPGP | 6,634.05 | 0.03% | 0.00% | 10.50% | 10.50% | 0.0029% |
| IQVIA Holdings Inc | IQV | 30,955.98 | 0.13% | 0.00% | 12.50% | 12.50% | 0.0162% |
| Ingersoll-Rand PLC | IR | 29,218.74 | 0.12% | 1.75% | 12.00% | 13.86% | 0.0169% |
| Iron Mountain Inc | IRM | 8,962.08 | 0.04% | 7.82% | 8.50% | 16.65% | 0.0062% |
| Intuitive Surgical Inc | ISRG | 59,836.04 | 0.25% | 0.00% | 14.00% | 14.00% | 0.0350% |
| Gartner Inc | IT | 11,940.45 | 0.05% | 0.00% | 14.00% | 14.00% | 0.0070% |
| Illinois Tool Works Inc | ITW | 48,799.98 | 0.20% | 2.84% | 9.00% | 11.97% | 0.0244% |
| Invesco Ltd | IVZ | 8,019.38 | 0.03% | 7.26% | 6.00% | 13.48% | 0.0045% |
| JB Hunt Transport Services Inc | JBHT | 10,599.93 | 0.04% | 1.07% | 10.00% | 11.12% | 0.0049% |
| Johnson Controls International plc | JCI | 33,897.12 | 0.14% | 2.44% | 2.00% | 4.46% | 0.0063% |
| Jacobs Engineering Group Inc | JEC | 11,619.17 | 0.05% | 0.80% | 12.50% | 13.35% | 0.0065% |
| Jefferies Financial Group Inc | JEF | 5,793.39 | 0.02% | 2.51% | 18.50% | 21.24% | 0.0051% |
| Jack Henry & Associates Inc | JKHY | 10,846.10 | 0.05% | 1.14% | 10.50% | 11.70% | 0.0053% |
| Johnson & Johnson | JNJ | 347,907.10 | 1.45% | 2.89% | 12.00% | 15.06% | 0.2189% |
| Juniper Networks Inc | JNPR | 8,822.65 | 0.04% | 2.97% | 6.00% | 9.06% | 0.0033% |
| JPMorgan Chase & Co | JPM | 356,382.90 | 1.49% | 3.28% | 8.50% | 11.92% | 0.1774% |
| Nordstrom Inc | JWN | 4,658.10 | 0.02% | 4.91% | 6.00% | 11.06% | 0.0022% |
| Kellogg Co | K | 21,309.09 | 0.09% | 3.68% | 4.00% | 7.75% | 0.0069% |
| KeyCorp | KEY | 16,571.44 | 0.07% | 4.48% | 10.50% | 15.22% | 0.0105% |
| Keysight Technologies Inc | KEYS | 16,745.18 | 0.07% | 0.00% | 19.00% | 19.00% | 0.0133% |
| Kraft Heinz Co/The | KHC | 34,428.40 | 0.14% | 5.81% | 2.00% | 7.87% | 0.0113% |
| Kimco Realty Corp | KIM | 8,040.10 | 0.03% | 5.98% | 5.00% | 11.13% | 0.0037% |
| KLA Corp | KLAC | 22,195.27 | 0.09% | 2.19% | 11.50% | 13.82% | 0.0128% |
| Kimberly-Clark Corp | KMB | 47,687.69 | 0.20% | 2.97% | 7.00% | 10.07% | 0.0201% |
| Kinder Morgan Inc/DE | KMI | 46,087.08 | 0.19% | 4.91% | 35.50% | 41.28% | 0.0795% |
| CarMax Inc | KMX | 13,898.14 | 0.06% | 0.00% | 10.50% | 10.50% | 0.0061% |
| Coca-Cola Co/The | KO | 229,524.80 | 0.96% | 2.98% | 6.50% | 9.58% | 0.0918% |
| Kroger Co/The | KR | 18,656.65 | 0.08% | 2.74% | 4.50% | 7.30% | 0.0057% |
| Kohl's Corp | KSS | 8,124.30 | 0.03% | 5.62% | 6.50% | 12.30% | 0.0042% |
| Kansas City Southern | KSU | 11,901.34 | 0.05% | 1.21% | 12.00% | 13.28% | 0.0066% |
| Loews Corp | L | 15,782.39 | 0.07% | 0.48% | 14.00% | 14.51% | 0.0096% |
| L Brands Inc | LB | 6,535.68 | 0.03% | 5.07% | -2.00% | 3.02% | 0.0008% |
| Leidos Holdings Inc | LDOS | 12,081.60 | 0.05% | 1.62% | 8.50% | 10.19% | 0.0051% |
| Leggett & Platt Inc | LEG | 5,197.01 | 0.02% | 4.05% | 9.00% | 13.23% | 0.0029% |
| Lennar Corp | LEN | 16,384.35 | 0.07% | 0.32% | 8.50% | 8.83% | 0.0060% |
| Laboratory Corp of America Holdings | LH | 16,082.23 | 0.07% | 0.00% | 8.00% | 8.00% | 0.0054% |
| L3Harris Technologies Inc | LHX | 25,320.54 | 0.11% | 1.29% | 12.00% | 13.37% | 0.0141% |
| Linde PLC | LIN | 104,719.40 | N/A | 1.95% | N/A | N/A | N/A |
| LKQ Corp | LKQ | 8,033.49 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0034% |
| Eli Lilly & Co | LLY | 110,030.40 | 0.46% | 2.26% | 11.50% | 13.89% | 0.0638% |
| Lockheed Martin Corp | LMT | 106,512.00 | 0.44% | 2.44% | 11.50% | 14.08% | 0.0626% |
| Lincoln National Corp | LNC | 11,612.89 | 0.05% | 2.73% | 9.00% | 11.85% | 0.0057% |
| Alliant Energy Corp | LNT | 12,194.33 | 0.05% | 2.77% | 6.50% | 9.36% | 0.0048% |
| Lowe's Cos Inc | LOW | 79,873.65 | 0.33% | 2.19% | 11.50% | 13.82% | 0.0461% |
| Lam Research Corp | LRCX | 30,199.03 | 0.13% | 2.18% | 11.00% | 13.30% | 0.0168% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Southwest Airlines Co | LUV | 27,139.23 | 0.11% | 1.43% | 11.00% | 12.51% | 0.0142% |
| Lamb Weston Holdings Inc | LW | 9,784.24 | N/A | 1.20% | N/A | N/A | N/A |
| LyondellBasell Industries NV | LYB | 28,563.25 | 0.12% | 5.45% | 5.50% | 11.10% | 0.0132% |
| Macy's Inc | M | 6,276.28 | 0.03% | 7.43% | 3.50% | 11.06% | 0.0029% |
| Mastercard Inc | MA | 282,488.60 | 1.18% | 0.48% | 16.00% | 16.52% | 0.1949% |
| Mid-America Apartment Communities Inc | MAA | 14,011.92 | 0.06% | 3.12% | 1.00% | 4.14% | 0.0024% |
| Macerich Co/The | MAC | 4,375.06 | 0.02% | 9.88% | 3.00% | 13.03% | 0.0024% |
| Marriott International Inc/MD | MAR | 42,928.65 | 0.18% | 1.47% | 11.50% | 13.05% | 0.0234% |
| Masco Corp | MAS | 11,447.14 | 0.05% | 1.26% | 10.50% | 11.83% | 0.0057% |
| McDonald's Corp | MCD | 165,556.80 | 0.69% | 2.20% | 8.50% | 10.79% | 0.0746% |
| Microchip Technology Inc | MCHP | 21,613.58 | 0.09% | 1.66% | 10.50% | 12.25% | 0.0111% |
| McKesson Corp | MCK | 25,992.50 | 0.11% | 1.17% | 8.50% | 9.72% | 0.0106% |
| Moody's Corp | MCO | 40,603.62 | 0.17% | 0.93% | 11.00% | 11.98% | 0.0203% |
| Mondelez International Inc | MDLZ | 79,732.45 | 0.33% | 2.08% | 8.50% | 10.67% | 0.0355% |
| Medtronic PLC | MDT | 137,126.50 | 0.57% | 2.11% | 8.50% | 10.70% | 0.0613% |
| MetLife Inc | MET | 44,820.04 | 0.19% | 3.77% | 7.50% | 11.41% | 0.0214% |
| MGM Resorts International | MGM | 15,211.03 | 0.06% | 1.80% | 14.00% | 15.93% | 0.0101% |
| Mohawk Industries Inc | MHK | 8,536.06 | 0.04% | 0.00% | 3.50% | 3.50% | 0.0012% |
| McCormick & Co Inc/MD | MKC | 21,498.37 | 0.09% | 1.44% | 8.00% | 9.50% | 0.0085% |
| MarketAxess Holdings Inc | MKTX | 13,302.65 | 0.06% | 0.58% | 14.00% | 14.62% | 0.0081% |
| Martin Marietta Materials Inc | MLM | 15,671.19 | 0.07% | 0.79% | 9.00% | 9.83% | 0.0064% |
| Marsh & McLennan Cos Inc | MMC | 50,529.41 | 0.21% | 1.85% | 9.00% | 10.93% | 0.0231% |
| 3M Co | MMM | 94,472.32 | 0.39% | 3.51% | 7.00% | 10.63% | 0.0420% |
| Monster Beverage Corp | MNST | 33,797.75 | 0.14% | 0.00% | 14.50% | 14.50% | 0.0205% |
| Altria Group Inc | MO | 86,866.14 | 0.36% | 6.88% | 8.50% | 15.67% | 0.0569% |
| Mosaic Co/The | MOS | 8,901.95 | 0.04% | 0.95% | 22.00% | 23.05% | 0.0086% |
| Marathon Petroleum Corp | MPC | 32,683.20 | 0.14% | 4.28% | 11.50% | 16.03% | 0.0219% |
| Merck & Co Inc | MRK | 217,484.50 | 0.91% | 2.60% | 8.50% | 11.21% | 0.1018% |
| Marathon Oil Corp | MRO | 10,545.20 | N/A | 1.56% | N/A | N/A | N/A |
| Morgan Stanley | MS | 69,581.05 | 0.29% | 3.39% | 10.00% | 13.56% | 0.0394% |
| MSCI Inc | MSCI | 19,096.18 | 0.08% | 1.21% | 18.50% | 19.82% | 0.0158% |
| Microsoft Corp | MSFT | 1,064,731.00 | 4.45% | 1.33% | 14.50% | 15.93% | 0.7083% |
| Motorola Solutions Inc | MSI | 29,562.81 | 0.12% | 1.27% | 10.50% | 11.84% | 0.0146% |
| M&T Bank Corp | MTB | 20,884.33 | 0.09% | 2.62% | 9.50% | 12.24% | 0.0107% |
| Mettler-Toledo International Inc | MTD | 17,556.55 | 0.07% | 0.00% | 10.00% | 10.00% | 0.0073% |
| Micron Technology Inc | MU | 47,063.52 | 0.20% | 0.00% | 11.50% | 11.50% | 0.0226% |
| Maxim Integrated Products Inc | MXIM | 15,076.00 | 0.06% | 3.47% | 8.00% | 11.61% | 0.0073% |
| Mylan NV | MYL | 9,847.81 | 0.04% | 0.00% | 0.50% | 0.50% | 0.0002% |
| Noble Energy Inc | NBL | 10,741.92 | N/A | 2.16% | N/A | N/A | N/A |
| Norwegian Cruise Line Holdings Ltd | NCLH | 10,473.49 | 0.04% | 0.00% | 16.00% | 16.00% | 0.0070% |
| Nasdaq Inc | NDAQ | 16,251.12 | 0.07% | 1.91% | 8.00% | 9.99% | 0.0068% |
| NextEra Energy Inc | NEE | 103,090.40 | 0.43% | 2.48% | 10.50% | 13.11% | 0.0564% |
| Newmont Goldcorp Corp | NEM | 32,213.64 | 0.13% | 1.43% | 2.50% | 3.95% | 0.0053% |
| Netflix Inc | NFLX | 138,312.10 | 0.58% | 0.00% | 32.00% | 32.00% | 0.1849% |
| NiSource Inc | NI | 10,749.57 | 0.04% | 2.78% | 12.50% | 15.45% | 0.0069% |
| NIKE Inc | NKE | 130,559.00 | 0.55% | 1.06% | 14.00% | 15.13% | 0.0825% |
| Nektar Therapeutics | NKTR | 5,151.92 | 0.02% | 0.00% | 15.50% | 15.50% | 0.0033% |
| Nielsen Holdings PLC | NLSN | 7,867.51 | 0.03% | 6.33% | 45.50% | 53.27% | 0.0175% |
| Northrop Grumman Corp | NOC | 62,467.14 | 0.26% | 1.43% | 9.50% | 11.00% | 0.0287% |
| National Oilwell Varco Inc | NOV | 8,042.82 | N/A | 0.96% | N/A | N/A | N/A |
| NRG Energy Inc | NRG | 9,081.01 | N/A | 0.34% | N/A | N/A | N/A |
| Norfolk Southern Corp | NSC | 47,547.60 | 0.20% | 2.08% | 15.00% | 17.24% | 0.0342% |
| NetApp Inc | NTAP | 11,794.25 | 0.05% | 4.02% | 18.50% | 22.89% | 0.0113% |
| Northern Trust Corp | NTRS | 19,462.68 | 0.08% | 3.09% | 8.50% | 11.72% | 0.0095% |
| Nucor Corp | NUE | 15,815.70 | 0.07% | 3.07% | 13.00% | 16.27% | 0.0107% |
| NVIDIA Corp | NVDA | 96,380.34 | 0.40% | 0.40% | 11.50% | 11.92% | 0.0480% |
| Newell Brands Inc | NWL | 6,859.08 | 0.03% | 5.68% | 4.50% | 10.31% | 0.0030% |
| News Corp | NWSA | 7,623.53 | N/A | 1.54% | N/A | N/A | N/A |
| Realty Income Corp | O | 21,866.39 | 0.09% | 3.93% | 4.50% | 8.52% | 0.0078% |
| ONEOK Inc | OKE | 28,469.81 | 0.12% | 5.44% | 16.00% | 21.88% | 0.0260% |
| Omnicom Group Inc | OMC | 17,143.07 | 0.07% | 3.43% | 6.50% | 10.04% | 0.0072% |
| Oracle Corp | ORCL | 183,569.40 | 0.77% | 1.76% | 10.00% | 11.85% | 0.0908% |
| O'Reilly Automotive Inc | ORLY | 29,264.14 | 0.12% | 0.00% | 12.00% | 12.00% | 0.0147% |
| Occidental Petroleum Corp | OXY | 35,267.61 | 0.15% | 6.71% | 27.50% | 35.13% | 0.0518% |
| Paychex Inc | PAYX | 30,336.96 | 0.13% | 3.08% | 10.50% | 13.74% | 0.0174% |
| People's United Financial Inc | PBCT | 6,098.89 | 0.03% | 4.64% | 9.00% | 13.85% | 0.0035% |
| PACCAR Inc | PCAR | 23,035.60 | 0.10% | 4.96% | 7.50% | 12.65% | 0.0122% |
| Public Service Enterprise Group Inc | PEG | 29,146.32 | 0.12% | 3.32% | 6.00% | 9.42% | 0.0115% |
| PepsiCo Inc | PEP | 181,128.50 | 0.76% | 2.95% | 6.50% | 9.55% | 0.0722% |
| Pfizer Inc | PFE | 205,071.00 | 0.86% | 3.91% | 11.00% | 15.13% | 0.1295% |
| Principal Financial Group Inc | PFG | 15,492.96 | 0.06% | 3.95% | 5.50% | 9.56% | 0.0062% |
| Procter & Gamble Co/The | PG | 294,578.30 | 1.23% | 2.54% | 8.50% | 11.15% | 0.1372% |
| Progressive Corp/The | PGR | 46,620.72 | 0.19% | 0.50% | 15.50% | 16.04% | 0.0312% |
| Parker-Hannifin Corp | PH | 21,480.04 | 0.09% | 2.10% | 11.50% | 13.72% | 0.0123% |
| PulteGroup Inc | PHM | 8,939.44 | 0.04% | 1.38% | 8.00% | 9.44% | 0.0035% |
| Packaging Corp of America | PKG | 9,670.76 | 0.04% | 3.09% | 6.00% | 9.18% | 0.0037% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| PerkinElmer Inc | PKI | 9,341.07 | 0.04% | 0.33% | 11.00% | 11.35% | 0.0044% |
| Prologis Inc | PLD | 51,735.54 | 0.22% | 2.68% | 6.50% | 9.27% | 0.0200% |
| Philip Morris International Inc | PM | 128,324.70 | 0.54% | 5.53% | 6.00% | 11.70% | 0.0627% |
| PNC Financial Services Group Inc/The | PNC | 58,820.73 | 0.25% | 3.50% | 8.00% | 11.64% | 0.0286% |
| Pentair PLC | PNR | 6,286.71 | 0.03% | 1.93% | 6.00% | 7.99% | 0.0021% |
| Pinnacle West Capital Corp | PNW | 10,419.47 | 0.04% | 3.28% | 5.50% | 8.87% | 0.0039% |
| PPG Industries Inc | PPG | 27,563.58 | 0.12% | 1.75% | 7.50% | 9.32% | 0.0107% |
| PPL Corp | PPL | 21,518.05 | 0.09% | 5.57% | 1.50% | 7.11% | 0.0064% |
| Perrigo Co PLC | PRGO | 6,400.03 | 0.03% | 1.79% | 2.00% | 3.81% | 0.0010% |
| Prudential Financial Inc | PRU | 35,044.32 | 0.15% | 4.65% | 7.00% | 11.81% | 0.0173% |
| Public Storage | PSA | 44,577.54 | 0.19% | 3.20% | 4.50% | 7.77% | 0.0145% |
| Phillips 66 | PSX | 45,172.67 | 0.19% | 3.67% | 10.00% | 13.85% | 0.0261% |
| PVH Corp | PVH | 5,902.54 | 0.02% | 0.19% | 9.50% | 9.70% | 0.0024% |
| Quanta Services Inc | PWR | 4,785.34 | 0.02% | 0.48% | 15.50% | 16.02% | 0.0032% |
| Pioneer Natural Resources Co | PXD | 21,352.54 | 0.09% | 1.18% | 37.50% | 38.90% | 0.0347% |
| PayPal Holdings Inc | PYPL | 125,691.80 | 0.52% | 0.00% | 20.00% | 20.00% | 0.1050% |
| QUALCOMM Inc | QCOM | 86,794.67 | 0.36% | 3.48% | 10.50% | 14.16% | 0.0513% |
| Qorvo Inc | QRVO | 8,498.97 | N/A | 0.00% | N/A | N/A | N/A |
| Royal Caribbean Cruises Ltd | RCL | 22,992.62 | 0.10% | 2.55% | 12.50% | 15.21% | 0.0146% |
| Everest Re Group Ltd | RE | 10,257.98 | 0.04% | 2.35% | 18.50% | 21.07% | 0.0090% |
| Regency Centers Corp | REG | 11,014.57 | 0.05% | 3.57% | 16.00% | 19.86% | 0.0091% |
| Regeneron Pharmaceuticals Inc | REGN | 33,364.32 | 0.14% | 0.00% | 10.00% | 10.00% | 0.0139% |
| Regions Financial Corp | RF | 14,776.23 | 0.06% | 4.21% | 10.50% | 14.93% | 0.0092% |
| Robert Half International Inc | RHI | 6,775.04 | 0.03% | 2.22% | 9.00% | 11.32% | 0.0032% |
| Raymond James Financial Inc | RJF | 10,768.33 | 0.04% | 1.82% | 10.00% | 11.91% | 0.0054% |
| Ralph Lauren Corp | RL | 7,489.17 | 0.03% | 2.84% | 8.00% | 10.95% | 0.0034% |
| ResMed Inc | RMD | 18,837.10 | 0.08% | 1.19% | 15.50% | 16.78% | 0.0132% |
| Rockwell Automation Inc | ROK | 18,297.63 | 0.08% | 2.50% | 9.50% | 12.12% | 0.0093% |
| Rollins Inc | ROL | 10,875.81 | 0.05% | 1.27% | 13.00% | 14.35% | 0.0065% |
| Roper Technologies Inc | ROP | 37,283.68 | 0.16% | 0.52% | 11.50% | 12.05% | 0.0188% |
| Ross Stores Inc | ROST | 39,097.43 | 0.16% | 1.00% | 9.50% | 10.55% | 0.0172% |
| Republic Services Inc | RSG | 31,695.87 | 0.13% | 1.80% | 11.50% | 13.40% | 0.0177% |
| Raytheon Co | RTN | 52,336.28 | 0.22% | 2.00% | 10.00% | 12.10% | 0.0264% |
| SBA Communications Corp | SBAC | 28,562.01 | 0.12% | 0.59% | 28.50% | 29.17% | 0.0348% |
| Starbucks Corp | SBUX | 116,149.80 | 0.49% | 1.66% | 13.50% | 15.27% | 0.0741% |
| Charles Schwab Corp/The | SCHW | 49,003.47 | 0.20% | 1.82% | 12.00% | 13.93% | 0.0285% |
| Sealed Air Corp | SEE | 7,002.48 | 0.03% | 1.41% | 22.50% | 24.07% | 0.0070% |
| Sherwin-Williams Co/The | SHW | 48,278.49 | 0.20% | 0.86% | 10.50% | 11.41% | 0.0230% |
| SVB Financial Group | SIVB | 10,758.97 | 0.04% | 0.00% | 15.00% | 15.00% | 0.0067% |
| JM Smucker Co/The | SJM | 12,914.27 | 0.05% | 3.10% | 5.00% | 8.18% | 0.0044% |
| Schlumberger Ltd | SLB | 48,695.61 | 0.20% | 5.68% | 19.50% | 25.73% | 0.0523% |
| SL Green Realty Corp | SLG | 6,645.23 | 0.03% | 4.49% | 5.50% | 10.11% | 0.0028% |
| Snap-on Inc | SNA | 8,528.13 | 0.04% | 2.75% | 6.00% | 8.83% | 0.0031% |
| Synopsys Inc | SNPS | 18,832.65 | 0.08% | 0.00% | 10.50% | 10.50% | 0.0083% |
| Southern Co/The | SO | 60,822.05 | 0.25% | 4.33% | 3.50% | 7.91% | 0.0201% |
| Simon Property Group Inc | SPG | 47,942.74 | 0.20% | 5.58% | 4.50% | 10.21% | 0.0204% |
| S&P Global Inc | SPGI | 63,491.22 | 0.27% | 0.88% | 13.00% | 13.94% | 0.0370% |
| Sempra Energy | SRE | 37,458.54 | 0.16% | 2.96% | 11.00% | 14.12% | 0.0221% |
| SunTrust Banks Inc | STI | 27,235.13 | 0.11% | 3.26% | 10.00% | 13.42% | 0.0153% |
| State Street Corp | STT | 19,899.13 | 0.08% | 3.89% | 5.00% | 8.99% | 0.0075% |
| Seagate Technology PLC | STX | 12,503.78 | 0.05% | 5.58% | 6.00% | 11.75% | 0.0061% |
| Constellation Brands Inc | STZ | 37,023.21 | 0.15% | 1.60% | 8.00% | 9.66% | 0.0149% |
| Stanley Black & Decker Inc | SWK | 21,152.97 | 0.09% | 1.98% | 9.00% | 11.07% | 0.0098% |
| Skyworks Solutions Inc | SWKS | 13,774.33 | 0.06% | 1.89% | 7.50% | 9.46% | 0.0054% |
| Synchrony Financial | SYF | 23,418.47 | 0.10% | 2.51% | 9.00% | 11.62% | 0.0114% |
| Stryker Corp | SYK | 81,475.24 | 0.34% | 0.96% | 13.00% | 14.02% | 0.0477% |
| Symantec Corp | SYMC | 14,439.60 | 0.06% | 1.31% | 7.00% | 8.36% | 0.0050% |
| Sysco Corp | SYY | 36,010.36 | 0.15% | 2.21% | 12.00% | 14.34% | 0.0216% |
| AT&T Inc | T | 252,315.70 | 1.05% | 5.96% | 5.50% | 11.62% | 0.1225% |
| Molson Coors Brewing Co | TAP | 11,266.26 | 0.05% | 4.33% | 5.50% | 9.95% | 0.0047% |
| TransDigm Group Inc | TDG | 29,353.18 | 0.12% | 0.00% | 11.00% | 11.00% | 0.0135% |
| TE Connectivity Ltd | TEL | 30,350.91 | 0.13% | 2.04% | 8.50% | 10.63% | 0.0135% |
| Teleflex Inc | TFX | 16,938.85 | 0.07% | 0.37% | 15.00% | 15.40% | 0.0109% |
| Target Corp | TGT | 42,931.75 | 0.18% | 3.15% | 8.00% | 11.28% | 0.0202% |
| Tiffany & Co | TIF | 11,066.82 | 0.05% | 2.58% | 10.50% | 13.22% | 0.0061% |
| TJX Cos Inc/The | TJX | 64,914.12 | 0.27% | 1.72% | 13.50% | 15.34% | 0.0416% |
| Thermo Fisher Scientific Inc | TMO | 112,333.50 | 0.47% | 0.27% | 10.00% | 10.28% | 0.0482% |
| T-Mobile US Inc | TMUS | 66,561.88 | 0.28% | 0.00% | 18.00% | 18.00% | 0.0500% |
| Tapestry Inc | TPR | 8,259.15 | 0.03% | 4.74% | 12.00% | 17.02% | 0.0059% |
| TripAdvisor Inc | TRIP | 6,013.14 | 0.03% | 0.00% | 19.50% | 19.50% | 0.0049% |
| T Rowe Price Group Inc | TROW | 25,965.86 | 0.11% | 2.83% | 10.00% | 12.97% | 0.0141% |
| Travelers Cos Inc/The | TRV | 38,818.82 | 0.16% | 2.21% | 9.00% | 11.31% | 0.0183% |
| Tractor Supply Co | TSCO | 13,163.12 | 0.05% | 1.28% | 11.50% | 12.85% | 0.0071% |
| Tyson Foods Inc | TSN | 32,375.50 | 0.14% | 1.75% | 7.00% | 8.81% | 0.0119% |
| Total System Services Inc | TSS | 22,902.59 | 0.10% | 0.40% | 10.00% | 10.42% | 0.0100% |
| Take-Two Interactive Software Inc | TTWO | 14,861.00 | 0.06% | 0.00% | 22.50% | 22.50% | 0.0140% |

| Company | Ticker | [4] Market Capitalization ($million) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Twitter Inc | TWTR | 32,494.57 | N/A | 0.00% | N/A | N/A | N/A |
| Texas Instruments Inc | TXN | 116,175.80 | 0.49% | 2.48% | 6.00% | 8.55% | 0.0415% |
| Textron Inc | TXT | 11,100.30 | 0.05% | 0.17% | 13.00% | 13.18% | 0.0061% |
| Under Armour Inc | UAA | 9,512.29 | 0.04% | 0.00% | 18.50% | 18.50% | 0.0074% |
| United Airlines Holdings Inc | UAL | 22,584.79 | 0.09% | 0.00% | 8.50% | 8.50% | 0.0080% |
| UDR Inc | UDR | 12,876.27 | 0.05% | 2.93% | 5.50% | 8.51% | 0.0046% |
| Universal Health Services Inc | UHS | 13,201.90 | 0.06% | 0.55% | 11.00% | 11.58% | 0.0064% |
| Ulta Beauty Inc | ULTA | 20,683.55 | 0.09% | 0.00% | 17.00% | 17.00% | 0.0147% |
| UnitedHealth Group Inc | UNH | 234,743.80 | 0.98% | 1.75% | 13.50% | 15.37% | 0.1507% |
| Unum Group | UNM | 6,137.30 | 0.03% | 3.94% | 8.50% | 12.61% | 0.0032% |
| Union Pacific Corp | UNP | 119,628.70 | 0.50% | 2.29% | 14.50% | 16.96% | 0.0847% |
| United Parcel Service Inc | UPS | 100,928.40 | 0.42% | 3.27% | 8.50% | 11.91% | 0.0502% |
| United Rentals Inc | URI | 9,125.36 | 0.04% | 0.00% | 14.50% | 14.50% | 0.0055% |
| US Bancorp | USB | 83,914.75 | 0.35% | 2.97% | 6.00% | 9.06% | 0.0318% |
| United Technologies Corp | UTX | 113,445.00 | 0.47% | 2.24% | 9.00% | 11.34% | 0.0537% |
| Visa Inc | V | 357,281.40 | 1.49% | 0.62% | 18.00% | 18.68% | 0.2787% |
| Varian Medical Systems Inc | VAR | 10,374.00 | 0.04% | 0.00% | 10.00% | 10.00% | 0.0043% |
| VF Corp | VFC | 33,286.17 | 0.14% | 2.06% | 7.00% | 9.13% | 0.0127% |
| Viacom Inc | VIAB | 12,425.89 | 0.05% | 2.60% | 6.00% | 8.68% | 0.0045% |
| Valero Energy Corp | VLO | 32,654.52 | 0.14% | 4.57% | 11.50% | 16.33% | 0.0223% |
| Vulcan Materials Co | VMC | 18,425.07 | 0.08% | 0.89% | 14.00% | 14.95% | 0.0115% |
| Vornado Realty Trust | VNO | 11,912.46 | 0.05% | 4.23% | -1.50% | 2.70% | 0.0013% |
| Verisk Analytics Inc | VRSK | 25,592.36 | 0.11% | 0.64% | 9.50% | 10.17% | 0.0109% |
| VeriSign Inc | VRSN | 25,051.56 | 0.10% | 0.00% | 11.00% | 11.00% | 0.0115% |
| Vertex Pharmaceuticals Inc | VRTX | 46,896.85 | 0.20% | 0.00% | 50.00% | 50.00% | 0.0979% |
| Ventas Inc | VTR | 25,630.40 | 0.11% | 4.49% | 4.00% | 8.58% | 0.0092% |
| Verizon Communications Inc | VZ | 230,858.40 | 0.96% | 4.39% | 4.00% | 8.48% | 0.0817% |
| Wabtec Corp | WAB | 13,517.18 | 0.06% | 0.67% | 13.50% | 14.22% | 0.0080% |
| Waters Corp | WAT | 14,401.03 | 0.06% | 0.00% | 10.00% | 10.00% | 0.0060% |
| Walgreens Boots Alliance Inc | WBA | 47,884.64 | 0.20% | 3.45% | 9.50% | 13.11% | 0.0262% |
| WellCare Health Plans Inc | WCG | 14,011.89 | 0.06% | 0.00% | 21.50% | 21.50% | 0.0126% |
| Western Digital Corp | WDC | 16,173.60 | 0.07% | 3.62% | 0.50% | 4.13% | 0.0028% |
| WEC Energy Group Inc | WEC | 28,168.44 | 0.12% | 2.72% | 6.00% | 8.80% | 0.0104% |
| Welltower Inc | WELL | 31,876.34 | 0.13% | 4.03% | 10.50% | 14.74% | 0.0196% |
| Wells Fargo & Co | WFC | 205,069.00 | 0.86% | 4.40% | 5.50% | 10.02% | 0.0858% |
| Whirlpool Corp | WHR | 8,945.37 | 0.04% | 3.38% | 6.50% | 9.99% | 0.0037% |
| Willis Towers Watson PLC | WLTW | 25,612.21 | 0.11% | 1.31% | 17.50% | 18.92% | 0.0202% |
| Waste Management Inc | WM | 50,207.70 | 0.21% | 1.73% | 8.00% | 9.80% | 0.0205% |
| Williams Cos Inc/The | WMB | 29,100.33 | 0.12% | 6.33% | 20.00% | 26.96% | 0.0328% |
| Walmart Inc | WMT | 310,584.30 | 1.30% | 1.96% | 7.50% | 9.53% | 0.1237% |
| Westrock Co | WRK | 8,959.19 | 0.04% | 5.23% | 9.50% | 14.98% | 0.0056% |
| Western Union Co/The | WU | 9,354.97 | 0.04% | 3.70% | 4.50% | 8.28% | 0.0032% |
| Weyerhaeuser Co | WY | 18,726.91 | 0.08% | 5.41% | 17.50% | 23.38% | 0.0183% |
| Wynn Resorts Ltd | WYNN | 11,999.59 | 0.05% | 3.59% | 14.50% | 18.35% | 0.0092% |
| Cimarex Energy Co | XEC | 4,479.02 | 0.02% | 1.81% | 18.00% | 19.97% | 0.0037% |
| Xcel Energy Inc | XEL | 31,736.28 | 0.13% | 2.71% | 5.50% | 8.28% | 0.0110% |
| Xilinx Inc | XLNX | 27,807.53 | 0.12% | 1.35% | 11.50% | 12.93% | 0.0150% |
| Exxon Mobil Corp | XOM | 306,239.80 | 1.28% | 4.81% | 14.50% | 19.66% | 0.2514% |
| DENTSPLY SIRONA Inc | XRAY | 11,736.12 | 0.05% | 0.67% | 4.50% | 5.19% | 0.0025% |
| Xerox Holdings Corp | XRX | 6,561.79 | 0.03% | 3.37% | 10.50% | 14.05% | 0.0038% |
| Xylem Inc/NY | XYL | 13,905.52 | 0.06% | 1.24% | 14.00% | 15.33% | 0.0089% |
| Yum! Brands Inc | YUM | 35,899.92 | 0.15% | 1.48% | 12.00% | 13.57% | 0.0203% |
| Zimmer Biomet Holdings Inc | ZBH | 28,466.76 | 0.12% | 0.71% | 4.50% | 5.23% | 0.0062% |
| Zions Bancorp NA | ZION | 7,454.27 | 0.03% | 3.23% | 9.50% | 12.88% | 0.0040% |
| Zoetis Inc | ZTS | 59,302.36 | 0.25% | 0.53% | 13.00% | 13.56% | 0.0336% |
| | | 23,942,412.37 | | | | | 14.62% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg and Value Line Beta Coefficients

| | | [1] | [2] |
|---|---|---|---|
| Company | Ticker | Bloomberg | Value Line |
| ALLETE, Inc. | ALE | 0.480 | 0.65 |
| Alliant Energy Corporation | LNT | 0.530 | 0.60 |
| Ameren Corporation | AEE | 0.475 | 0.60 |
| American Electric Power Company, Inc. | AEP | 0.514 | 0.55 |
| Avangrid, Inc. | AGR | 0.478 | 0.40 |
| CMS Energy Corporation | CMS | 0.481 | 0.55 |
| DTE Energy Company | DTE | 0.511 | 0.55 |
| Evergy, Inc | EVRG | 0.450 | 0.52 |
| Hawaiian Electric Industries, Inc. | HE | 0.495 | 0.55 |
| NextEra Energy, Inc. | NEE | 0.544 | 0.55 |
| NorthWestern Corporation | NWE | 0.504 | 0.60 |
| OGE Energy Corp. | OGE | 0.557 | 0.80 |
| Otter Tail Corporation | OTTR | 0.563 | 0.70 |
| Pinnacle West Capital Corporation | PNW | 0.441 | 0.55 |
| PNM Resources, Inc. | PNM | 0.529 | 0.60 |
| Portland General Electric Company | POR | 0.488 | 0.60 |
| Southern Company | SO | 0.464 | 0.50 |
| WEC Energy Group, Inc. | WEC | 0.479 | 0.50 |
| Xcel Energy Inc. | XEL | 0.502 | 0.50 |
| Mean | | 0.499 | 0.57 |

Notes:

[1] Source: Bloomberg Professional

[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the Beta coefficient for Evergy has been manually calculated according to Value Line's methodology.

Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

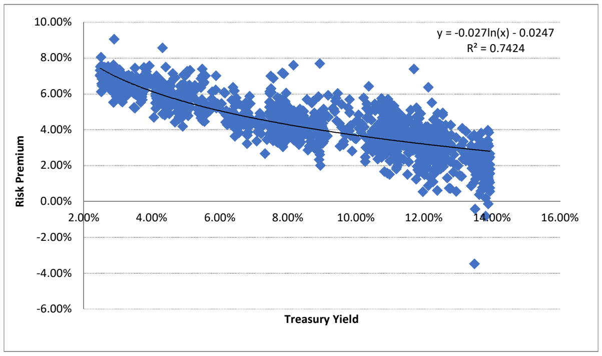
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|
| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM | |
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP BLOOMBERG BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury (30-day average) [9] | 2.43% | 0.499 | 12.04% | 12.19% | 8.44% | 8.52% | 9.95% | 10.04% |
| Near-Term Projected 30-Year Treasury [10] | 2.65% | 0.499 | 12.04% | 12.19% | 8.66% | 8.74% | 10.17% | 10.26% |
| Mean | | | | | 8.55% | 8.63% | 10.06% | 10.15% |

| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM | |
|---|---|---|---|---|---|---|---|---|
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury (30-day average) [9] | 2.43% | 0.572 | 12.04% | 12.19% | 9.32% | 9.41% | 10.61% | 10.71% |
| Near-Term Projected 30-Year Treasury [10] | 2.65% | 0.572 | 12.04% | 12.19% | 9.54% | 9.62% | 10.83% | 10.93% |
| Mean | | | | | 9.43% | 9.51% | 10.72% | 10.82% |

Notes:
[1] *See Notes [9] and [10]*
[2] Source: Exhibit No. RBH-3
[3] Source: Exhibit No. RBH-2
[4] Source: Exhibit No. RBH-2
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Equals Col. [1] + (0.75 x(Col. [2] x Col. [3]) + (0.25 x Col. [3])
[8] Equals Col. [1] + (0.75 x(Col. [2] x Col. [4]) + (0.25 x Col. [4])
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 38, No. 8, August 1, 2019, at 2.

Bond Yield Plus Risk Premium

| | [1] | [2] | [3] | [4] | [5] |
|---|---|---|---|---|---|
| | Constant | Slope | 30-Year Treasury Yield | Risk Premium | Return on Equity |
| | -2.47% | -2.68% | | | |
| Current 30-Year Treasury | | | 2.43% | 7.48% | 9.91% |
| Near-Term Projected 30-Year Treasury | | | 2.65% | 7.25% | 9.90% |
| Long-Term Projected 30-Year Treasury | | | 3.70% | 6.36% | 10.06% |




Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 8, August 1, 2019, at 2.
Long Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 6, June 1, 2019, at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Global Market Intelligence
[7] Source: S&P Global Market Intelligence
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

| [6] Date of Electric Rate Case | [7] Return on Equity | [8] 30-Year Treasury Yield | [9] Risk Premium |
|---|---|---|---|
| 1/1/1980 | 14.50% | 9.36% | 5.14% |
| 1/7/1980 | 14.39% | 9.38% | 5.01% |
| 1/9/1980 | 15.00% | 9.40% | 5.60% |
| 1/14/1980 | 15.17% | 9.42% | 5.75% |
| 1/17/1980 | 13.93% | 9.44% | 4.49% |
| 1/23/1980 | 15.50% | 9.47% | 6.03% |
| 1/30/1980 | 13.86% | 9.52% | 4.34% |
| 1/31/1980 | 12.61% | 9.53% | 3.08% |
| 2/6/1980 | 13.71% | 9.58% | 4.13% |
| 2/13/1980 | 12.80% | 9.63% | 3.17% |
| 2/14/1980 | 13.00% | 9.65% | 3.35% |
| 2/19/1980 | 13.50% | 9.68% | 3.82% |
| 2/27/1980 | 13.75% | 9.78% | 3.97% |
| 2/29/1980 | 13.75% | 9.81% | 3.94% |
| 2/29/1980 | 14.00% | 9.81% | 4.19% |
| 2/29/1980 | 14.77% | 9.81% | 4.96% |
| 3/7/1980 | 12.70% | 9.89% | 2.81% |
| 3/14/1980 | 13.50% | 9.97% | 3.53% |
| 3/26/1980 | 14.16% | 10.10% | 4.06% |
| 3/27/1980 | 14.24% | 10.12% | 4.12% |
| 3/28/1980 | 14.50% | 10.13% | 4.37% |
| 4/11/1980 | 12.75% | 10.27% | 2.48% |
| 4/14/1980 | 13.85% | 10.29% | 3.56% |
| 4/16/1980 | 15.50% | 10.31% | 5.19% |
| 4/22/1980 | 13.25% | 10.35% | 2.90% |
| 4/22/1980 | 13.90% | 10.35% | 3.55% |
| 4/24/1980 | 16.80% | 10.38% | 6.43% |
| 4/29/1980 | 15.50% | 10.41% | 5.09% |
| 5/6/1980 | 13.70% | 10.45% | 3.25% |
| 5/7/1980 | 15.00% | 10.45% | 4.55% |
| 5/8/1980 | 13.75% | 10.46% | 3.29% |
| 5/9/1980 | 14.35% | 10.47% | 3.88% |
| 5/13/1980 | 13.60% | 10.48% | 3.12% |
| 5/15/1980 | 13.25% | 10.49% | 2.76% |
| 5/19/1980 | 13.75% | 10.51% | 3.24% |
| 5/27/1980 | 13.62% | 10.54% | 3.08% |
| 5/27/1980 | 14.60% | 10.54% | 4.06% |
| 5/29/1980 | 16.00% | 10.56% | 5.44% |
| 5/30/1980 | 13.80% | 10.56% | 3.24% |
| 6/2/1980 | 15.63% | 10.57% | 5.06% |
| 6/9/1980 | 15.90% | 10.60% | 5.30% |
| 6/10/1980 | 13.78% | 10.60% | 3.18% |
| 6/12/1980 | 14.25% | 10.61% | 3.64% |
| 6/19/1980 | 13.40% | 10.62% | 2.78% |
| 6/30/1980 | 13.00% | 10.65% | 2.35% |
| 6/30/1980 | 13.40% | 10.65% | 2.75% |
| 7/9/1980 | 14.75% | 10.67% | 4.08% |
| 7/10/1980 | 15.00% | 10.68% | 4.32% |
| 7/15/1980 | 15.80% | 10.70% | 5.10% |
| 7/18/1980 | 13.80% | 10.71% | 3.09% |
| 7/22/1980 | 14.10% | 10.72% | 3.38% |
| 7/24/1980 | 15.00% | 10.73% | 4.27% |
| 7/25/1980 | 13.48% | 10.73% | 2.75% |
| 7/31/1980 | 14.58% | 10.75% | 3.83% |
| 8/8/1980 | 13.50% | 10.78% | 2.72% |
| 8/8/1980 | 14.00% | 10.78% | 3.22% |
| 8/8/1980 | 15.45% | 10.78% | 4.67% |
| 8/11/1980 | 14.85% | 10.78% | 4.07% |
| 8/14/1980 | 14.00% | 10.79% | 3.21% |
| 8/14/1980 | 16.25% | 10.79% | 5.46% |
| 8/25/1980 | 13.75% | 10.82% | 2.93% |
| 8/27/1980 | 13.80% | 10.83% | 2.97% |
| 8/29/1980 | 12.50% | 10.84% | 1.66% |
| 9/15/1980 | 13.50% | 10.88% | 2.62% |
| 9/15/1980 | 13.93% | 10.88% | 3.05% |
| 9/15/1980 | 15.80% | 10.88% | 4.92% |
| 9/24/1980 | 12.50% | 10.93% | 1.57% |
| 9/24/1980 | 15.00% | 10.93% | 4.07% |
| 9/26/1980 | 13.75% | 10.94% | 2.81% |
| 9/30/1980 | 14.10% | 10.96% | 3.14% |
| 9/30/1980 | 14.20% | 10.96% | 3.24% |
| 10/1/1980 | 13.90% | 10.97% | 2.93% |
| 10/3/1980 | 15.50% | 10.98% | 4.52% |
| 10/7/1980 | 12.50% | 10.99% | 1.51% |
| 10/9/1980 | 13.25% | 11.00% | 2.25% |
| 10/9/1980 | 14.50% | 11.00% | 3.50% |
| 10/9/1980 | 14.50% | 11.00% | 3.50% |
| 10/16/1980 | 16.10% | 11.02% | 5.08% |
| 10/17/1980 | 14.50% | 11.03% | 3.47% |
| 10/31/1980 | 13.75% | 11.11% | 2.64% |
| 10/31/1980 | 14.25% | 11.11% | 3.14% |
| 11/4/1980 | 15.00% | 11.12% | 3.88% |
| 11/5/1980 | 13.75% | 11.12% | 2.63% |
| 11/5/1980 | 14.00% | 11.12% | 2.88% |
| 11/8/1980 | 13.75% | 11.14% | 2.61% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 11/10/1980 | 14.85% | 11.15% | 3.70% |
| 11/17/1980 | 14.00% | 11.18% | 2.82% |
| 11/18/1980 | 14.00% | 11.19% | 2.81% |
| 11/19/1980 | 13.00% | 11.19% | 1.81% |
| 11/24/1980 | 14.00% | 11.21% | 2.79% |
| 11/26/1980 | 14.00% | 11.21% | 2.79% |
| 12/8/1980 | 14.15% | 11.22% | 2.93% |
| 12/8/1980 | 15.10% | 11.22% | 3.88% |
| 12/9/1980 | 15.35% | 11.22% | 4.13% |
| 12/12/1980 | 15.45% | 11.23% | 4.22% |
| 12/17/1980 | 13.25% | 11.23% | 2.02% |
| 12/18/1980 | 15.80% | 11.23% | 4.57% |
| 12/19/1980 | 14.50% | 11.23% | 3.27% |
| 12/19/1980 | 14.64% | 11.23% | 3.41% |
| 12/22/1980 | 13.45% | 11.23% | 2.22% |
| 12/22/1980 | 15.00% | 11.23% | 3.77% |
| 12/30/1980 | 14.50% | 11.22% | 3.28% |
| 12/30/1980 | 14.95% | 11.22% | 3.73% |
| 12/31/1980 | 13.39% | 11.22% | 2.17% |
| 1/2/1981 | 15.25% | 11.22% | 4.03% |
| 1/7/1981 | 14.30% | 11.21% | 3.09% |
| 1/19/1981 | 15.25% | 11.20% | 4.05% |
| 1/23/1981 | 13.10% | 11.20% | 1.90% |
| 1/23/1981 | 14.40% | 11.20% | 3.20% |
| 1/26/1981 | 15.25% | 11.20% | 4.05% |
| 1/27/1981 | 15.00% | 11.21% | 3.79% |
| 1/31/1981 | 13.47% | 11.22% | 2.25% |
| 2/3/1981 | 15.25% | 11.23% | 4.02% |
| 2/5/1981 | 15.75% | 11.25% | 4.50% |
| 2/11/1981 | 15.60% | 11.28% | 4.32% |
| 2/20/1981 | 15.25% | 11.33% | 3.92% |
| 3/11/1981 | 15.40% | 11.49% | 3.91% |
| 3/12/1981 | 14.51% | 11.50% | 3.01% |
| 3/12/1981 | 16.00% | 11.50% | 4.50% |
| 3/13/1981 | 13.02% | 11.52% | 1.50% |
| 3/18/1981 | 16.19% | 11.55% | 4.64% |
| 3/19/1981 | 13.75% | 11.56% | 2.19% |
| 3/23/1981 | 14.30% | 11.58% | 2.72% |
| 3/25/1981 | 15.30% | 11.60% | 3.70% |
| 4/1/1981 | 14.53% | 11.68% | 2.85% |
| 4/3/1981 | 19.10% | 11.71% | 7.39% |
| 4/9/1981 | 15.00% | 11.78% | 3.22% |
| 4/9/1981 | 15.30% | 11.78% | 3.52% |
| 4/9/1981 | 16.50% | 11.78% | 4.72% |
| 4/9/1981 | 17.00% | 11.78% | 5.22% |
| 4/10/1981 | 13.75% | 11.80% | 1.95% |
| 4/13/1981 | 13.57% | 11.82% | 1.75% |
| 4/15/1981 | 15.30% | 11.85% | 3.45% |
| 4/16/1981 | 13.50% | 11.87% | 1.63% |
| 4/17/1981 | 14.10% | 11.87% | 2.23% |
| 4/21/1981 | 14.00% | 11.90% | 2.10% |
| 4/21/1981 | 16.80% | 11.90% | 4.90% |
| 4/24/1981 | 16.00% | 11.95% | 4.05% |
| 4/27/1981 | 12.50% | 11.97% | 0.53% |
| 4/27/1981 | 13.61% | 11.97% | 1.64% |
| 4/29/1981 | 13.65% | 12.00% | 1.65% |
| 4/30/1981 | 13.50% | 12.02% | 1.48% |
| 5/4/1981 | 16.22% | 12.05% | 4.17% |
| 5/5/1981 | 14.40% | 12.07% | 2.33% |
| 5/7/1981 | 16.25% | 12.11% | 4.14% |
| 5/7/1981 | 16.27% | 12.11% | 4.16% |
| 5/8/1981 | 13.00% | 12.13% | 0.87% |
| 5/8/1981 | 16.00% | 12.13% | 3.87% |
| 5/12/1981 | 13.50% | 12.16% | 1.34% |
| 5/15/1981 | 15.75% | 12.22% | 3.53% |
| 5/18/1981 | 14.88% | 12.23% | 2.65% |
| 5/20/1981 | 16.00% | 12.26% | 3.74% |
| 5/21/1981 | 14.00% | 12.27% | 1.73% |
| 5/26/1981 | 14.90% | 12.30% | 2.60% |
| 5/27/1981 | 15.00% | 12.31% | 2.69% |
| 5/29/1981 | 15.50% | 12.34% | 3.16% |
| 6/1/1981 | 16.50% | 12.35% | 4.15% |
| 6/3/1981 | 14.67% | 12.37% | 2.30% |
| 6/5/1981 | 13.00% | 12.39% | 0.61% |
| 6/10/1981 | 16.75% | 12.42% | 4.33% |
| 6/17/1981 | 14.40% | 12.46% | 1.94% |
| 6/18/1981 | 16.33% | 12.47% | 3.86% |
| 6/25/1981 | 14.75% | 12.51% | 2.24% |
| 6/26/1981 | 16.00% | 12.52% | 3.48% |
| 6/30/1981 | 15.25% | 12.54% | 2.71% |
| 7/1/1981 | 15.50% | 12.56% | 2.94% |
| 7/1/1981 | 17.50% | 12.56% | 4.94% |
| 7/10/1981 | 16.00% | 12.62% | 3.38% |
| 7/14/1981 | 16.90% | 12.64% | 4.26% |
| 7/15/1981 | 16.00% | 12.65% | 3.35% |
| 7/17/1981 | 15.00% | 12.67% | 2.33% |
| 7/20/1981 | 15.00% | 12.68% | 2.32% |
| 7/21/1981 | 14.00% | 12.69% | 1.31% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 7/28/1981 | 13.48% | 12.74% | 0.74% |
| 7/31/1981 | 13.50% | 12.78% | 0.72% |
| 7/31/1981 | 15.00% | 12.78% | 2.22% |
| 7/31/1981 | 16.00% | 12.78% | 3.22% |
| 8/5/1981 | 15.71% | 12.83% | 2.88% |
| 8/10/1981 | 14.50% | 12.87% | 1.63% |
| 8/11/1981 | 15.00% | 12.88% | 2.12% |
| 8/20/1981 | 13.50% | 12.95% | 0.55% |
| 8/20/1981 | 16.50% | 12.95% | 3.55% |
| 8/24/1981 | 15.00% | 12.97% | 2.03% |
| 8/28/1981 | 15.00% | 13.01% | 1.99% |
| 9/3/1981 | 14.50% | 13.05% | 1.45% |
| 9/10/1981 | 14.50% | 13.11% | 1.39% |
| 9/11/1981 | 16.00% | 13.12% | 2.88% |
| 9/16/1981 | 16.00% | 13.15% | 2.85% |
| 9/17/1981 | 16.50% | 13.16% | 3.34% |
| 9/23/1981 | 15.85% | 13.20% | 2.65% |
| 9/28/1981 | 15.50% | 13.23% | 2.27% |
| 10/9/1981 | 15.75% | 13.33% | 2.42% |
| 10/15/1981 | 16.25% | 13.37% | 2.88% |
| 10/16/1981 | 15.50% | 13.38% | 2.12% |
| 10/16/1981 | 16.50% | 13.38% | 3.12% |
| 10/19/1981 | 14.25% | 13.39% | 0.86% |
| 10/20/1981 | 15.25% | 13.41% | 1.84% |
| 10/20/1981 | 17.00% | 13.41% | 3.59% |
| 10/23/1981 | 16.00% | 13.45% | 2.55% |
| 10/27/1981 | 10.00% | 13.48% | -3.48% |
| 10/29/1981 | 14.75% | 13.51% | 1.24% |
| 10/29/1981 | 16.50% | 13.51% | 2.99% |
| 11/3/1981 | 15.17% | 13.53% | 1.64% |
| 11/5/1981 | 16.60% | 13.55% | 3.05% |
| 11/6/1981 | 15.17% | 13.56% | 1.61% |
| 11/24/1981 | 15.50% | 13.61% | 1.89% |
| 11/25/1981 | 15.25% | 13.61% | 1.64% |
| 11/25/1981 | 15.35% | 13.61% | 1.74% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 12/1/1981 | 15.70% | 13.61% | 2.09% |
| 12/1/1981 | 16.00% | 13.61% | 2.39% |
| 12/1/1981 | 16.49% | 13.61% | 2.88% |
| 12/1/1981 | 16.50% | 13.61% | 2.89% |
| 12/4/1981 | 16.00% | 13.61% | 2.39% |
| 12/11/1981 | 16.25% | 13.63% | 2.62% |
| 12/14/1981 | 14.00% | 13.63% | 0.37% |
| 12/15/1981 | 15.81% | 13.63% | 2.18% |
| 12/15/1981 | 16.00% | 13.63% | 2.37% |
| 12/16/1981 | 15.25% | 13.63% | 1.62% |
| 12/17/1981 | 16.50% | 13.63% | 2.87% |
| 12/18/1981 | 15.45% | 13.63% | 1.82% |
| 12/30/1981 | 14.25% | 13.67% | 0.58% |
| 12/30/1981 | 16.00% | 13.67% | 2.33% |
| 12/30/1981 | 16.25% | 13.67% | 2.58% |
| 12/31/1981 | 16.15% | 13.67% | 2.48% |
| 1/4/1982 | 15.50% | 13.67% | 1.83% |
| 1/11/1982 | 14.50% | 13.72% | 0.78% |
| 1/11/1982 | 17.00% | 13.72% | 3.28% |
| 1/13/1982 | 14.75% | 13.74% | 1.01% |
| 1/14/1982 | 15.75% | 13.75% | 2.00% |
| 1/15/1982 | 15.00% | 13.76% | 1.24% |
| 1/15/1982 | 16.50% | 13.76% | 2.74% |
| 1/22/1982 | 16.25% | 13.79% | 2.46% |
| 1/27/1982 | 16.84% | 13.81% | 3.03% |
| 1/28/1982 | 13.00% | 13.81% | -0.81% |
| 1/29/1982 | 15.50% | 13.82% | 1.68% |
| 2/1/1982 | 15.85% | 13.82% | 2.03% |
| 2/3/1982 | 16.44% | 13.84% | 2.60% |
| 2/8/1982 | 15.50% | 13.86% | 1.64% |
| 2/11/1982 | 16.00% | 13.88% | 2.12% |
| 2/11/1982 | 16.20% | 13.88% | 2.32% |
| 2/17/1982 | 15.00% | 13.89% | 1.11% |
| 2/19/1982 | 15.17% | 13.89% | 1.28% |
| 2/26/1982 | 15.25% | 13.89% | 1.36% |
| 3/1/1982 | 15.03% | 13.89% | 1.14% |
| 3/1/1982 | 16.00% | 13.89% | 2.11% |
| 3/3/1982 | 15.00% | 13.88% | 1.12% |
| 3/8/1982 | 17.10% | 13.88% | 3.22% |
| 3/12/1982 | 16.25% | 13.88% | 2.37% |
| 3/17/1982 | 17.30% | 13.88% | 3.42% |
| 3/22/1982 | 15.10% | 13.89% | 1.21% |
| 3/27/1982 | 15.40% | 13.89% | 1.51% |
| 3/30/1982 | 15.50% | 13.90% | 1.60% |
| 3/31/1982 | 17.00% | 13.91% | 3.09% |
| 4/1/1982 | 14.70% | 13.91% | 0.79% |
| 4/1/1982 | 16.50% | 13.91% | 2.59% |
| 4/2/1982 | 15.50% | 13.91% | 1.59% |
| 4/5/1982 | 15.50% | 13.92% | 1.58% |
| 4/8/1982 | 16.40% | 13.93% | 2.47% |
| 4/13/1982 | 14.50% | 13.94% | 0.56% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 4/23/1982 | 15.75% | 13.94% | 1.81% |
| 4/27/1982 | 15.00% | 13.94% | 1.06% |
| 4/28/1982 | 15.75% | 13.94% | 1.81% |
| 4/30/1982 | 14.70% | 13.94% | 0.76% |
| 4/30/1982 | 15.50% | 13.94% | 1.56% |
| 5/3/1982 | 16.60% | 13.94% | 2.66% |
| 5/4/1982 | 16.00% | 13.94% | 2.06% |
| 5/14/1982 | 15.50% | 13.92% | 1.58% |
| 5/18/1982 | 15.42% | 13.92% | 1.50% |
| 5/19/1982 | 14.69% | 13.92% | 0.77% |
| 5/20/1982 | 15.00% | 13.91% | 1.09% |
| 5/20/1982 | 15.10% | 13.91% | 1.19% |
| 5/20/1982 | 15.50% | 13.91% | 1.59% |
| 5/20/1982 | 16.30% | 13.91% | 2.39% |
| 5/21/1982 | 17.75% | 13.91% | 3.84% |
| 5/27/1982 | 15.00% | 13.89% | 1.11% |
| 5/28/1982 | 15.50% | 13.89% | 1.61% |
| 5/28/1982 | 17.00% | 13.89% | 3.11% |
| 6/1/1982 | 13.75% | 13.89% | -0.14% |
| 6/1/1982 | 16.60% | 13.89% | 2.71% |
| 6/9/1982 | 17.86% | 13.88% | 3.98% |
| 6/14/1982 | 15.75% | 13.88% | 1.87% |
| 6/15/1982 | 14.85% | 13.88% | 0.97% |
| 6/18/1982 | 15.50% | 13.87% | 1.63% |
| 6/21/1982 | 14.90% | 13.87% | 1.03% |
| 6/23/1982 | 16.00% | 13.86% | 2.14% |
| 6/23/1982 | 16.17% | 13.86% | 2.31% |
| 6/24/1982 | 14.85% | 13.86% | 0.99% |
| 6/25/1982 | 14.70% | 13.86% | 0.84% |
| 7/1/1982 | 16.00% | 13.84% | 2.16% |
| 7/2/1982 | 15.62% | 13.84% | 1.78% |
| 7/2/1982 | 17.00% | 13.84% | 3.16% |
| 7/13/1982 | 14.00% | 13.82% | 0.18% |
| 7/13/1982 | 16.80% | 13.82% | 2.98% |
| 7/14/1982 | 15.76% | 13.82% | 1.94% |
| 7/14/1982 | 16.02% | 13.82% | 2.20% |
| 7/19/1982 | 16.50% | 13.80% | 2.70% |
| 7/22/1982 | 14.50% | 13.77% | 0.73% |
| 7/22/1982 | 17.00% | 13.77% | 3.23% |
| 7/27/1982 | 16.75% | 13.75% | 3.00% |
| 7/29/1982 | 16.50% | 13.74% | 2.76% |
| 8/11/1982 | 17.50% | 13.68% | 3.82% |
| 8/18/1982 | 17.07% | 13.63% | 3.44% |
| 8/20/1982 | 15.73% | 13.60% | 2.13% |
| 8/25/1982 | 16.00% | 13.57% | 2.43% |
| 8/26/1982 | 15.50% | 13.56% | 1.94% |
| 8/30/1982 | 15.00% | 13.55% | 1.45% |
| 9/3/1982 | 16.20% | 13.53% | 2.67% |
| 9/8/1982 | 15.00% | 13.52% | 1.48% |
| 9/15/1982 | 13.08% | 13.50% | -0.42% |
| 9/15/1982 | 16.25% | 13.50% | 2.75% |
| 9/16/1982 | 16.00% | 13.50% | 2.50% |
| 9/17/1982 | 15.25% | 13.50% | 1.75% |
| 9/23/1982 | 17.17% | 13.47% | 3.70% |
| 9/24/1982 | 14.50% | 13.46% | 1.04% |
| 9/27/1982 | 15.25% | 13.46% | 1.79% |
| 10/1/1982 | 15.50% | 13.42% | 2.08% |
| 10/15/1982 | 15.90% | 13.32% | 2.58% |
| 10/22/1982 | 15.75% | 13.24% | 2.51% |
| 10/22/1982 | 17.15% | 13.24% | 3.91% |
| 10/29/1982 | 15.54% | 13.16% | 2.38% |
| 11/1/1982 | 15.50% | 13.15% | 2.35% |
| 11/3/1982 | 17.20% | 13.13% | 4.07% |
| 11/4/1982 | 16.25% | 13.11% | 3.14% |
| 11/5/1982 | 16.20% | 13.09% | 3.11% |
| 11/9/1982 | 16.00% | 13.05% | 2.95% |
| 11/23/1982 | 15.50% | 12.89% | 2.61% |
| 11/23/1982 | 15.85% | 12.89% | 2.96% |
| 11/30/1982 | 16.50% | 12.81% | 3.69% |
| 12/1/1982 | 17.04% | 12.79% | 4.25% |
| 12/6/1982 | 15.00% | 12.73% | 2.27% |
| 12/6/1982 | 16.35% | 12.73% | 3.62% |
| 12/10/1982 | 15.50% | 12.66% | 2.84% |
| 12/13/1982 | 16.00% | 12.65% | 3.35% |
| 12/14/1982 | 15.30% | 12.63% | 2.67% |
| 12/14/1982 | 16.40% | 12.63% | 3.77% |
| 12/20/1982 | 16.00% | 12.57% | 3.43% |
| 12/21/1982 | 14.75% | 12.56% | 2.19% |
| 12/21/1982 | 15.85% | 12.56% | 3.29% |
| 12/22/1982 | 16.25% | 12.54% | 3.71% |
| 12/22/1982 | 16.58% | 12.54% | 4.04% |
| 12/22/1982 | 16.75% | 12.54% | 4.21% |
| 12/29/1982 | 14.90% | 12.48% | 2.42% |
| 12/29/1982 | 16.25% | 12.48% | 3.77% |
| 12/30/1982 | 16.00% | 12.47% | 3.53% |
| 12/30/1982 | 16.35% | 12.47% | 3.88% |
| 12/30/1982 | 16.77% | 12.47% | 4.30% |
| 1/5/1983 | 17.33% | 12.40% | 4.93% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 1/11/1983 | 15.90% | 12.34% | 3.56% |
| 1/12/1983 | 14.63% | 12.33% | 2.30% |
| 1/12/1983 | 15.50% | 12.33% | 3.17% |
| 1/20/1983 | 17.75% | 12.24% | 5.51% |
| 1/21/1983 | 15.00% | 12.22% | 2.78% |
| 1/24/1983 | 14.50% | 12.21% | 2.29% |
| 1/24/1983 | 15.50% | 12.21% | 3.29% |
| 1/25/1983 | 15.85% | 12.19% | 3.66% |
| 1/27/1983 | 16.14% | 12.17% | 3.97% |
| 2/1/1983 | 18.50% | 12.13% | 6.37% |
| 2/4/1983 | 14.00% | 12.10% | 1.90% |
| 2/10/1983 | 15.00% | 12.06% | 2.94% |
| 2/21/1983 | 15.50% | 11.98% | 3.52% |
| 2/22/1983 | 15.50% | 11.97% | 3.53% |
| 2/23/1983 | 15.10% | 11.96% | 3.14% |
| 2/23/1983 | 16.00% | 11.96% | 4.04% |
| 3/2/1983 | 15.25% | 11.89% | 3.36% |
| 3/9/1983 | 15.20% | 11.82% | 3.38% |
| 3/15/1983 | 13.00% | 11.77% | 1.23% |
| 3/18/1983 | 15.25% | 11.73% | 3.52% |
| 3/23/1983 | 15.40% | 11.69% | 3.71% |
| 3/24/1983 | 15.00% | 11.67% | 3.33% |
| 3/29/1983 | 15.50% | 11.63% | 3.87% |
| 3/30/1983 | 16.71% | 11.61% | 5.10% |
| 3/31/1983 | 15.00% | 11.59% | 3.41% |
| 4/4/1983 | 15.20% | 11.58% | 3.62% |
| 4/8/1983 | 15.50% | 11.51% | 3.99% |
| 4/11/1983 | 14.81% | 11.49% | 3.32% |
| 4/19/1983 | 14.50% | 11.38% | 3.12% |
| 4/20/1983 | 16.00% | 11.36% | 4.64% |
| 4/29/1983 | 16.00% | 11.24% | 4.76% |
| 5/1/1983 | 14.50% | 11.24% | 3.26% |
| 5/9/1983 | 15.50% | 11.15% | 4.35% |
| 5/11/1983 | 16.46% | 11.12% | 5.34% |
| 5/12/1983 | 14.14% | 11.11% | 3.03% |
| 5/18/1983 | 15.00% | 11.05% | 3.95% |
| 5/23/1983 | 14.90% | 11.01% | 3.89% |
| 5/23/1983 | 15.50% | 11.01% | 4.49% |
| 5/25/1983 | 15.50% | 10.98% | 4.52% |
| 5/27/1983 | 15.00% | 10.96% | 4.04% |
| 5/31/1983 | 14.00% | 10.95% | 3.05% |
| 5/31/1983 | 15.50% | 10.95% | 4.55% |
| 6/2/1983 | 14.50% | 10.93% | 3.57% |
| 6/17/1983 | 15.03% | 10.84% | 4.19% |
| 7/1/1983 | 14.80% | 10.78% | 4.02% |
| 7/1/1983 | 14.90% | 10.78% | 4.12% |
| 7/8/1983 | 16.25% | 10.76% | 5.49% |
| 7/13/1983 | 13.20% | 10.75% | 2.45% |
| 7/19/1983 | 15.00% | 10.74% | 4.26% |
| 7/19/1983 | 15.10% | 10.74% | 4.36% |
| 7/25/1983 | 16.25% | 10.73% | 5.52% |
| 7/28/1983 | 15.90% | 10.74% | 5.16% |
| 8/3/1983 | 16.34% | 10.75% | 5.59% |
| 8/3/1983 | 16.50% | 10.75% | 5.75% |
| 8/19/1983 | 15.00% | 10.80% | 4.20% |
| 8/22/1983 | 15.50% | 10.80% | 4.70% |
| 8/22/1983 | 16.40% | 10.80% | 5.60% |
| 8/31/1983 | 14.75% | 10.84% | 3.91% |
| 9/7/1983 | 15.00% | 10.86% | 4.14% |
| 9/14/1983 | 15.78% | 10.89% | 4.89% |
| 9/16/1983 | 15.00% | 10.90% | 4.10% |
| 9/19/1983 | 14.50% | 10.91% | 3.59% |
| 9/20/1983 | 16.50% | 10.91% | 5.59% |
| 9/28/1983 | 14.50% | 10.94% | 3.56% |
| 9/29/1983 | 15.50% | 10.95% | 4.55% |
| 9/30/1983 | 15.25% | 10.95% | 4.30% |
| 9/30/1983 | 16.15% | 10.95% | 5.20% |
| 10/4/1983 | 14.80% | 10.96% | 3.84% |
| 10/7/1983 | 16.00% | 10.97% | 5.03% |
| 10/13/1983 | 15.52% | 10.99% | 4.53% |
| 10/17/1983 | 15.50% | 11.00% | 4.50% |
| 10/18/1983 | 14.50% | 11.00% | 3.50% |
| 10/19/1983 | 16.25% | 11.01% | 5.24% |
| 10/19/1983 | 16.50% | 11.01% | 5.49% |
| 10/26/1983 | 15.00% | 11.04% | 3.96% |
| 10/27/1983 | 15.20% | 11.04% | 4.16% |
| 11/1/1983 | 16.00% | 11.06% | 4.94% |
| 11/9/1983 | 14.90% | 11.09% | 3.81% |
| 11/10/1983 | 14.35% | 11.10% | 3.25% |
| 11/23/1983 | 16.00% | 11.13% | 4.87% |
| 11/23/1983 | 16.15% | 11.13% | 5.02% |
| 11/30/1983 | 15.00% | 11.14% | 3.86% |
| 12/5/1983 | 15.25% | 11.15% | 4.10% |
| 12/6/1983 | 15.07% | 11.15% | 3.92% |
| 12/8/1983 | 15.90% | 11.16% | 4.74% |
| 12/9/1983 | 14.75% | 11.17% | 3.58% |
| 12/12/1983 | 14.50% | 11.17% | 3.33% |
| 12/15/1983 | 15.56% | 11.19% | 4.37% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/19/1983 | 14.80% | 11.21% | 3.59% |
| 12/20/1983 | 14.69% | 11.22% | 3.47% |
| 12/20/1983 | 16.00% | 11.22% | 4.78% |
| 12/20/1983 | 16.25% | 11.22% | 5.03% |
| 12/22/1983 | 14.75% | 11.23% | 3.52% |
| 12/22/1983 | 15.75% | 11.23% | 4.52% |
| 1/3/1984 | 14.75% | 11.27% | 3.48% |
| 1/10/1984 | 15.90% | 11.30% | 4.60% |
| 1/12/1984 | 15.60% | 11.31% | 4.29% |
| 1/18/1984 | 13.75% | 11.33% | 2.42% |
| 1/19/1984 | 15.90% | 11.33% | 4.57% |
| 1/30/1984 | 16.10% | 11.37% | 4.73% |
| 1/31/1984 | 15.25% | 11.37% | 3.88% |
| 2/1/1984 | 14.80% | 11.38% | 3.42% |
| 2/6/1984 | 13.75% | 11.40% | 2.35% |
| 2/6/1984 | 14.75% | 11.40% | 3.35% |
| 2/9/1984 | 15.25% | 11.42% | 3.83% |
| 2/15/1984 | 15.70% | 11.44% | 4.26% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/22/1984 | 14.75% | 11.47% | 3.28% |
| 2/28/1984 | 14.50% | 11.51% | 2.99% |
| 3/2/1984 | 14.25% | 11.54% | 2.71% |
| 3/20/1984 | 16.00% | 11.64% | 4.36% |
| 3/23/1984 | 15.50% | 11.67% | 3.83% |
| 3/26/1984 | 14.71% | 11.68% | 3.03% |
| 4/2/1984 | 15.50% | 11.71% | 3.79% |
| 4/6/1984 | 14.74% | 11.75% | 2.99% |
| 4/11/1984 | 15.72% | 11.78% | 3.94% |
| 4/17/1984 | 15.00% | 11.81% | 3.19% |
| 4/18/1984 | 16.20% | 11.82% | 4.38% |
| 4/25/1984 | 14.64% | 11.85% | 2.79% |
| 4/30/1984 | 14.40% | 11.87% | 2.53% |
| 5/16/1984 | 14.69% | 11.98% | 2.71% |
| 5/16/1984 | 15.00% | 11.98% | 3.02% |
| 5/22/1984 | 14.40% | 12.02% | 2.38% |
| 5/29/1984 | 15.10% | 12.06% | 3.04% |
| 6/13/1984 | 15.25% | 12.15% | 3.10% |
| 6/15/1984 | 15.60% | 12.17% | 3.43% |
| 6/22/1984 | 16.25% | 12.21% | 4.04% |
| 6/29/1984 | 15.25% | 12.26% | 2.99% |
| 7/2/1984 | 13.35% | 12.27% | 1.08% |
| 7/10/1984 | 16.00% | 12.31% | 3.69% |
| 7/12/1984 | 16.50% | 12.32% | 4.18% |
| 7/13/1984 | 16.25% | 12.33% | 3.92% |
| 7/17/1984 | 14.14% | 12.35% | 1.79% |
| 7/18/1984 | 15.30% | 12.36% | 2.94% |
| 7/18/1984 | 15.50% | 12.36% | 3.14% |
| 7/19/1984 | 14.30% | 12.37% | 1.93% |
| 7/24/1984 | 16.79% | 12.39% | 4.40% |
| 7/31/1984 | 16.00% | 12.43% | 3.57% |
| 8/3/1984 | 14.25% | 12.44% | 1.81% |
| 8/17/1984 | 14.30% | 12.49% | 1.81% |
| 8/20/1984 | 15.00% | 12.49% | 2.51% |
| 8/27/1984 | 16.30% | 12.51% | 3.79% |
| 8/31/1984 | 15.55% | 12.52% | 3.03% |
| 9/6/1984 | 16.00% | 12.53% | 3.47% |
| 9/10/1984 | 14.75% | 12.54% | 2.21% |
| 9/13/1984 | 15.00% | 12.55% | 2.45% |
| 9/17/1984 | 17.38% | 12.56% | 4.82% |
| 9/26/1984 | 14.50% | 12.57% | 1.93% |
| 9/28/1984 | 15.00% | 12.57% | 2.43% |
| 9/28/1984 | 16.25% | 12.57% | 3.68% |
| 10/9/1984 | 14.75% | 12.58% | 2.17% |
| 10/12/1984 | 15.60% | 12.59% | 3.01% |
| 10/22/1984 | 15.00% | 12.59% | 2.41% |
| 10/26/1984 | 16.40% | 12.58% | 3.82% |
| 10/31/1984 | 16.25% | 12.58% | 3.67% |
| 11/7/1984 | 15.60% | 12.58% | 3.02% |
| 11/9/1984 | 16.00% | 12.58% | 3.42% |
| 11/14/1984 | 15.75% | 12.58% | 3.17% |
| 11/20/1984 | 15.25% | 12.58% | 2.67% |
| 11/20/1984 | 15.92% | 12.58% | 3.34% |
| 11/23/1984 | 15.00% | 12.58% | 2.42% |
| 11/28/1984 | 16.15% | 12.57% | 3.58% |
| 12/3/1984 | 15.80% | 12.56% | 3.24% |
| 12/4/1984 | 16.50% | 12.56% | 3.94% |
| 12/18/1984 | 16.40% | 12.53% | 3.87% |
| 12/19/1984 | 14.75% | 12.53% | 2.22% |
| 12/19/1984 | 15.00% | 12.53% | 2.47% |
| 12/20/1984 | 16.00% | 12.53% | 3.47% |
| 12/28/1984 | 16.00% | 12.50% | 3.50% |
| 1/3/1985 | 14.75% | 12.49% | 2.26% |
| 1/10/1985 | 15.75% | 12.47% | 3.28% |
| 1/11/1985 | 16.30% | 12.46% | 3.84% |
| 1/23/1985 | 15.80% | 12.43% | 3.37% |
| 1/24/1985 | 15.82% | 12.43% | 3.39% |
| 1/25/1985 | 16.75% | 12.42% | 4.33% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 1/30/1985 | 14.90% | 12.40% | 2.50% |
| 1/31/1985 | 14.75% | 12.39% | 2.36% |
| 2/8/1985 | 14.47% | 12.35% | 2.12% |
| 3/1/1985 | 13.84% | 12.31% | 1.53% |
| 3/8/1985 | 16.85% | 12.28% | 4.57% |
| 3/14/1985 | 15.50% | 12.25% | 3.25% |
| 3/15/1985 | 15.62% | 12.25% | 3.37% |
| 3/29/1985 | 15.62% | 12.17% | 3.45% |
| 4/3/1985 | 14.60% | 12.14% | 2.46% |
| 4/9/1985 | 15.50% | 12.11% | 3.39% |
| 4/16/1985 | 15.70% | 12.06% | 3.64% |
| 4/22/1985 | 14.00% | 12.02% | 1.98% |
| 4/26/1985 | 15.50% | 11.98% | 3.52% |
| 4/29/1985 | 15.00% | 11.97% | 3.03% |
| 5/2/1985 | 14.68% | 11.94% | 2.74% |
| 5/8/1985 | 15.62% | 11.89% | 3.73% |
| 5/10/1985 | 16.50% | 11.87% | 4.63% |
| 5/29/1985 | 14.61% | 11.73% | 2.88% |
| 5/31/1985 | 16.00% | 11.71% | 4.29% |
| 6/14/1985 | 15.50% | 11.61% | 3.89% |
| 7/9/1985 | 15.00% | 11.45% | 3.55% |
| 7/16/1985 | 14.50% | 11.39% | 3.11% |
| 7/26/1985 | 14.50% | 11.33% | 3.17% |
| 8/2/1985 | 14.80% | 11.29% | 3.51% |
| 8/7/1985 | 15.00% | 11.27% | 3.73% |
| 8/28/1985 | 14.25% | 11.15% | 3.10% |
| 8/28/1985 | 15.50% | 11.15% | 4.35% |
| 8/29/1985 | 14.50% | 11.15% | 3.35% |
| 9/9/1985 | 14.60% | 11.11% | 3.49% |
| 9/9/1985 | 14.90% | 11.11% | 3.79% |
| 9/17/1985 | 14.90% | 11.08% | 3.82% |
| 9/23/1985 | 15.00% | 11.06% | 3.94% |
| 9/27/1985 | 15.50% | 11.05% | 4.45% |
| 9/27/1985 | 15.80% | 11.05% | 4.75% |
| 10/2/1985 | 14.00% | 11.03% | 2.97% |
| 10/2/1985 | 14.75% | 11.03% | 3.72% |
| 10/3/1985 | 15.25% | 11.03% | 4.22% |
| 10/24/1985 | 15.40% | 10.96% | 4.44% |
| 10/24/1985 | 15.82% | 10.96% | 4.86% |
| 10/24/1985 | 15.85% | 10.96% | 4.89% |
| 10/28/1985 | 16.00% | 10.95% | 5.05% |
| 10/29/1985 | 16.65% | 10.94% | 5.71% |
| 10/31/1985 | 15.06% | 10.93% | 4.13% |
| 11/4/1985 | 14.50% | 10.92% | 3.58% |
| 11/7/1985 | 15.50% | 10.90% | 4.60% |
| 11/8/1985 | 14.30% | 10.89% | 3.41% |
| 12/12/1985 | 14.75% | 10.73% | 4.02% |
| 12/18/1985 | 15.00% | 10.69% | 4.31% |
| 12/20/1985 | 14.50% | 10.67% | 3.83% |
| 12/20/1985 | 14.50% | 10.67% | 3.83% |
| 12/20/1985 | 15.00% | 10.67% | 4.33% |
| 1/24/1986 | 15.40% | 10.41% | 4.99% |
| 1/31/1986 | 15.00% | 10.35% | 4.65% |
| 2/5/1986 | 15.00% | 10.32% | 4.68% |
| 2/5/1986 | 15.75% | 10.32% | 5.43% |
| 2/10/1986 | 13.30% | 10.29% | 3.01% |
| 2/11/1986 | 12.50% | 10.28% | 2.22% |
| 2/14/1986 | 14.40% | 10.24% | 4.16% |
| 2/18/1986 | 16.00% | 10.23% | 5.77% |
| 2/24/1986 | 14.50% | 10.18% | 4.32% |
| 2/26/1986 | 14.00% | 10.15% | 3.85% |
| 3/5/1986 | 14.90% | 10.08% | 4.82% |
| 3/11/1986 | 14.50% | 10.02% | 4.48% |
| 3/12/1986 | 13.50% | 10.00% | 3.50% |
| 3/27/1986 | 14.10% | 9.86% | 4.24% |
| 3/31/1986 | 13.50% | 9.84% | 3.66% |
| 4/1/1986 | 14.00% | 9.83% | 4.17% |
| 4/2/1986 | 15.50% | 9.81% | 5.69% |
| 4/4/1986 | 15.00% | 9.78% | 5.22% |
| 4/14/1986 | 13.40% | 9.69% | 3.71% |
| 4/23/1986 | 15.00% | 9.57% | 5.43% |
| 5/16/1986 | 14.50% | 9.32% | 5.18% |
| 5/16/1986 | 14.50% | 9.32% | 5.18% |
| 5/29/1986 | 13.90% | 9.19% | 4.71% |
| 5/30/1986 | 15.10% | 9.18% | 5.92% |
| 6/2/1986 | 12.81% | 9.17% | 3.64% |
| 6/11/1986 | 14.00% | 9.07% | 4.93% |
| 6/24/1986 | 16.63% | 8.94% | 7.69% |
| 6/26/1986 | 12.00% | 8.91% | 3.09% |
| 6/26/1986 | 14.75% | 8.91% | 5.84% |
| 6/30/1986 | 13.00% | 8.87% | 4.13% |
| 7/10/1986 | 14.34% | 8.75% | 5.59% |
| 7/11/1986 | 12.75% | 8.73% | 4.02% |
| 7/14/1986 | 12.60% | 8.71% | 3.89% |
| 7/17/1986 | 12.40% | 8.66% | 3.74% |
| 7/25/1986 | 14.25% | 8.57% | 5.68% |
| 8/6/1986 | 13.50% | 8.44% | 5.06% |
| 8/14/1986 | 13.50% | 8.35% | 5.15% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/16/1986 | 12.75% | 8.06% | 4.69% |
| 9/19/1986 | 13.25% | 8.03% | 5.22% |
| 10/1/1986 | 14.00% | 7.95% | 6.05% |
| 10/3/1986 | 13.40% | 7.93% | 5.47% |
| 10/31/1986 | 13.50% | 7.77% | 5.73% |
| 11/5/1986 | 13.00% | 7.75% | 5.25% |
| 12/3/1986 | 12.90% | 7.58% | 5.32% |
| 12/4/1986 | 14.44% | 7.58% | 6.86% |
| 12/16/1986 | 13.60% | 7.52% | 6.08% |
| 12/22/1986 | 13.80% | 7.51% | 6.29% |
| 12/30/1986 | 13.00% | 7.49% | 5.51% |
| 1/2/1987 | 13.00% | 7.49% | 5.51% |
| 1/12/1987 | 12.40% | 7.47% | 4.93% |
| 1/27/1987 | 12.71% | 7.46% | 5.25% |
| 3/2/1987 | 12.47% | 7.47% | 5.00% |
| 3/3/1987 | 13.60% | 7.47% | 6.13% |
| 3/4/1987 | 12.38% | 7.47% | 4.91% |
| 3/10/1987 | 13.50% | 7.47% | 6.03% |
| 3/13/1987 | 13.00% | 7.47% | 5.53% |
| 3/31/1987 | 13.00% | 7.46% | 5.54% |
| 4/6/1987 | 13.00% | 7.47% | 5.53% |
| 4/14/1987 | 12.50% | 7.49% | 5.01% |
| 4/16/1987 | 14.50% | 7.50% | 7.00% |
| 4/27/1987 | 12.00% | 7.54% | 4.46% |
| 5/5/1987 | 12.85% | 7.58% | 5.27% |
| 5/12/1987 | 12.65% | 7.62% | 5.03% |
| 5/28/1987 | 13.50% | 7.70% | 5.80% |
| 6/15/1987 | 13.20% | 7.78% | 5.42% |
| 6/29/1987 | 15.00% | 7.83% | 7.17% |
| 6/30/1987 | 12.50% | 7.84% | 4.66% |
| 7/8/1987 | 12.00% | 7.86% | 4.14% |
| 7/10/1987 | 12.90% | 7.86% | 5.04% |
| 7/15/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 15.00% | 7.88% | 7.12% |
| 7/27/1987 | 13.00% | 7.92% | 5.08% |
| 7/27/1987 | 13.40% | 7.92% | 5.48% |
| 7/27/1987 | 13.50% | 7.92% | 5.58% |
| 7/31/1987 | 12.98% | 7.95% | 5.03% |
| 8/26/1987 | 12.63% | 8.06% | 4.57% |
| 8/26/1987 | 12.75% | 8.06% | 4.69% |
| 8/27/1987 | 13.25% | 8.06% | 5.19% |
| 9/9/1987 | 13.00% | 8.14% | 4.86% |
| 9/30/1987 | 12.75% | 8.31% | 4.44% |
| 9/30/1987 | 13.00% | 8.31% | 4.69% |
| 10/2/1987 | 11.50% | 8.33% | 3.17% |
| 10/15/1987 | 13.00% | 8.43% | 4.57% |
| 11/2/1987 | 13.00% | 8.55% | 4.45% |
| 11/19/1987 | 13.00% | 8.64% | 4.36% |
| 11/30/1987 | 12.00% | 8.68% | 3.32% |
| 12/3/1987 | 14.20% | 8.70% | 5.50% |
| 12/15/1987 | 13.25% | 8.77% | 4.48% |
| 12/16/1987 | 13.50% | 8.78% | 4.72% |
| 12/16/1987 | 13.72% | 8.78% | 4.94% |
| 12/17/1987 | 11.75% | 8.79% | 2.96% |
| 12/18/1987 | 13.50% | 8.80% | 4.70% |
| 12/21/1987 | 12.01% | 8.81% | 3.20% |
| 12/22/1987 | 12.00% | 8.81% | 3.19% |
| 12/22/1987 | 12.00% | 8.81% | 3.19% |
| 12/22/1987 | 12.75% | 8.81% | 3.94% |
| 12/22/1987 | 13.00% | 8.81% | 4.19% |
| 1/20/1988 | 13.80% | 8.94% | 4.86% |
| 1/26/1988 | 13.90% | 8.95% | 4.95% |
| 1/29/1988 | 13.20% | 8.96% | 4.24% |
| 2/4/1988 | 12.60% | 8.96% | 3.64% |
| 3/1/1988 | 11.56% | 8.94% | 2.62% |
| 3/23/1988 | 12.87% | 8.92% | 3.95% |
| 3/24/1988 | 11.24% | 8.92% | 2.32% |
| 3/30/1988 | 12.72% | 8.92% | 3.80% |
| 4/1/1988 | 12.50% | 8.92% | 3.58% |
| 4/7/1988 | 13.25% | 8.93% | 4.32% |
| 4/25/1988 | 10.96% | 8.96% | 2.00% |
| 5/3/1988 | 12.91% | 8.97% | 3.94% |
| 5/11/1988 | 13.50% | 8.99% | 4.51% |
| 5/16/1988 | 13.00% | 8.99% | 4.01% |
| 6/30/1988 | 12.75% | 9.00% | 3.75% |
| 7/1/1988 | 12.75% | 8.99% | 3.76% |
| 7/20/1988 | 13.40% | 8.96% | 4.44% |
| 8/5/1988 | 12.75% | 8.92% | 3.83% |
| 8/23/1988 | 11.70% | 8.93% | 2.77% |
| 8/29/1988 | 12.75% | 8.94% | 3.81% |
| 8/30/1988 | 13.50% | 8.94% | 4.56% |
| 9/8/1988 | 12.60% | 8.95% | 3.65% |
| 10/13/1988 | 13.10% | 8.93% | 4.17% |
| 12/19/1988 | 13.00% | 9.02% | 3.98% |
| 12/20/1988 | 12.25% | 9.02% | 3.23% |
| 12/20/1988 | 13.00% | 9.02% | 3.98% |
| 12/21/1988 | 12.90% | 9.02% | 3.88% |

I/A

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/27/1988 | 13.00% | 9.03% | 3.97% |
| 12/28/1988 | 13.10% | 9.03% | 4.07% |
| 12/30/1988 | 13.40% | 9.04% | 4.36% |
| 1/27/1989 | 13.00% | 9.05% | 3.95% |
| 1/31/1989 | 13.00% | 9.05% | 3.95% |
| 2/17/1989 | 13.00% | 9.05% | 3.95% |
| 2/20/1989 | 12.40% | 9.05% | 3.35% |
| 3/1/1989 | 12.76% | 9.05% | 3.71% |
| 3/8/1989 | 13.00% | 9.05% | 3.95% |
| 3/30/1989 | 14.00% | 9.05% | 4.95% |
| 4/5/1989 | 14.20% | 9.05% | 5.15% |
| 4/18/1989 | 13.00% | 9.05% | 3.95% |
| 5/5/1989 | 12.40% | 9.05% | 3.35% |
| 6/2/1989 | 13.20% | 9.00% | 4.20% |
| 6/8/1989 | 13.50% | 8.98% | 4.52% |
| 6/27/1989 | 13.25% | 8.91% | 4.34% |
| 6/30/1989 | 13.00% | 8.90% | 4.10% |
| 8/14/1989 | 12.50% | 8.77% | 3.73% |
| 9/28/1989 | 12.25% | 8.63% | 3.62% |
| 10/24/1989 | 12.50% | 8.54% | 3.96% |
| 11/9/1989 | 13.00% | 8.49% | 4.51% |
| 12/15/1989 | 13.00% | 8.34% | 4.66% |
| 12/20/1989 | 12.90% | 8.32% | 4.58% |
| 12/21/1989 | 12.90% | 8.31% | 4.59% |
| 12/27/1989 | 12.50% | 8.29% | 4.21% |
| 12/27/1989 | 13.00% | 8.29% | 4.71% |
| 1/10/1990 | 12.80% | 8.24% | 4.56% |
| 1/11/1990 | 12.90% | 8.24% | 4.66% |
| 1/17/1990 | 12.80% | 8.22% | 4.58% |
| 1/26/1990 | 12.00% | 8.20% | 3.80% |
| 2/9/1990 | 12.10% | 8.17% | 3.93% |
| 2/24/1990 | 12.86% | 8.15% | 4.71% |
| 3/30/1990 | 12.90% | 8.16% | 4.74% |
| 4/4/1990 | 15.76% | 8.17% | 7.59% |
| 4/12/1990 | 12.52% | 8.18% | 4.34% |
| 4/19/1990 | 12.75% | 8.20% | 4.55% |
| 5/21/1990 | 12.10% | 8.28% | 3.82% |
| 5/29/1990 | 12.40% | 8.30% | 4.10% |
| 5/31/1990 | 12.00% | 8.30% | 3.70% |
| 6/4/1990 | 12.90% | 8.30% | 4.60% |
| 6/6/1990 | 12.25% | 8.31% | 3.94% |
| 6/15/1990 | 13.20% | 8.32% | 4.88% |
| 6/20/1990 | 12.92% | 8.32% | 4.60% |
| 6/27/1990 | 12.90% | 8.33% | 4.57% |
| 6/29/1990 | 12.50% | 8.33% | 4.17% |
| 7/6/1990 | 12.10% | 8.34% | 3.76% |
| 7/6/1990 | 12.35% | 8.34% | 4.01% |
| 8/10/1990 | 12.55% | 8.41% | 4.14% |
| 8/16/1990 | 13.21% | 8.43% | 4.78% |
| 8/22/1990 | 13.10% | 8.45% | 4.65% |
| 8/24/1990 | 13.00% | 8.46% | 4.54% |
| 9/26/1990 | 11.45% | 8.59% | 2.86% |
| 10/2/1990 | 13.00% | 8.61% | 4.39% |
| 10/5/1990 | 12.84% | 8.62% | 4.22% |
| 10/19/1990 | 13.00% | 8.67% | 4.33% |
| 10/25/1990 | 12.30% | 8.68% | 3.62% |
| 11/21/1990 | 12.70% | 8.69% | 4.01% |
| 12/13/1990 | 12.30% | 8.67% | 3.63% |
| 12/17/1990 | 12.87% | 8.67% | 4.20% |
| 12/18/1990 | 13.10% | 8.67% | 4.43% |
| 12/19/1990 | 12.00% | 8.66% | 3.34% |
| 12/20/1990 | 12.75% | 8.66% | 4.09% |
| 12/21/1990 | 12.50% | 8.66% | 3.84% |
| 12/27/1990 | 12.79% | 8.66% | 4.13% |
| 1/2/1991 | 13.10% | 8.65% | 4.45% |
| 1/4/1991 | 12.50% | 8.65% | 3.85% |
| 1/15/1991 | 12.75% | 8.64% | 4.11% |
| 1/25/1991 | 11.70% | 8.63% | 3.07% |
| 2/4/1991 | 12.50% | 8.60% | 3.90% |
| 2/7/1991 | 12.50% | 8.59% | 3.91% |
| 2/12/1991 | 13.00% | 8.58% | 4.43% |
| 2/14/1991 | 12.72% | 8.57% | 4.15% |
| 2/22/1991 | 12.80% | 8.55% | 4.25% |
| 3/6/1991 | 13.10% | 8.53% | 4.57% |
| 3/8/1991 | 12.30% | 8.52% | 3.78% |
| 3/8/1991 | 13.00% | 8.52% | 4.48% |
| 4/22/1991 | 13.00% | 8.49% | 4.51% |
| 5/7/1991 | 13.50% | 8.47% | 5.03% |
| 5/13/1991 | 13.25% | 8.47% | 4.78% |
| 5/30/1991 | 12.75% | 8.44% | 4.31% |
| 6/12/1991 | 12.00% | 8.41% | 3.59% |
| 6/25/1991 | 11.70% | 8.39% | 3.31% |
| 6/28/1991 | 12.50% | 8.38% | 4.12% |
| 7/1/1991 | 12.00% | 8.38% | 3.62% |
| 7/3/1991 | 12.50% | 8.37% | 4.13% |
| 7/19/1991 | 12.10% | 8.34% | 3.76% |
| 8/1/1991 | 12.90% | 8.32% | 4.58% |
| 8/16/1991 | 13.20% | 8.29% | 4.91% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/27/1991 | 12.50% | 8.23% | 4.27% |
| 9/30/1991 | 12.25% | 8.23% | 4.02% |
| 10/17/1991 | 13.00% | 8.20% | 4.80% |
| 10/23/1991 | 12.50% | 8.20% | 4.30% |
| 10/23/1991 | 12.55% | 8.20% | 4.35% |
| 10/31/1991 | 11.80% | 8.19% | 3.61% |
| 11/1/1991 | 12.00% | 8.19% | 3.81% |
| 11/5/1991 | 12.25% | 8.19% | 4.06% |
| 11/12/1991 | 12.50% | 8.18% | 4.32% |
| 11/12/1991 | 13.25% | 8.18% | 5.07% |
| 11/25/1991 | 12.40% | 8.18% | 4.22% |
| 11/26/1991 | 11.60% | 8.18% | 3.42% |
| 11/26/1991 | 12.50% | 8.18% | 4.32% |
| 11/27/1991 | 12.10% | 8.18% | 3.92% |
| 12/18/1991 | 12.25% | 8.15% | 4.10% |
| 12/19/1991 | 12.60% | 8.15% | 4.45% |
| 12/19/1991 | 12.80% | 8.15% | 4.65% |
| 12/20/1991 | 12.65% | 8.14% | 4.51% |
| 1/9/1992 | 12.80% | 8.09% | 4.71% |
| 1/16/1992 | 12.75% | 8.07% | 4.68% |
| 1/21/1992 | 12.00% | 8.06% | 3.94% |
| 1/22/1992 | 13.00% | 8.06% | 4.94% |
| 1/27/1992 | 12.65% | 8.05% | 4.60% |
| 1/31/1992 | 12.00% | 8.04% | 3.96% |
| 2/11/1992 | 12.40% | 8.03% | 4.37% |
| 2/25/1992 | 12.50% | 8.01% | 4.49% |
| 3/16/1992 | 11.43% | 7.98% | 3.45% |
| 3/18/1992 | 12.28% | 7.98% | 4.30% |
| 4/2/1992 | 12.10% | 7.95% | 4.15% |
| 4/9/1992 | 11.45% | 7.94% | 3.51% |
| 4/10/1992 | 11.50% | 7.93% | 3.57% |
| 4/14/1992 | 11.50% | 7.93% | 3.57% |
| 5/5/1992 | 11.50% | 7.89% | 3.61% |
| 5/12/1992 | 11.87% | 7.88% | 3.99% |
| 5/12/1992 | 12.46% | 7.88% | 4.58% |
| 6/1/1992 | 12.30% | 7.87% | 4.43% |
| 6/12/1992 | 10.90% | 7.86% | 3.04% |
| 6/26/1992 | 12.35% | 7.85% | 4.50% |
| 6/29/1992 | 11.00% | 7.85% | 3.15% |
| 6/30/1992 | 13.00% | 7.85% | 5.15% |
| 7/13/1992 | 11.90% | 7.84% | 4.06% |
| 7/13/1992 | 13.50% | 7.84% | 5.66% |
| 7/22/1992 | 11.20% | 7.83% | 3.37% |
| 8/3/1992 | 12.00% | 7.81% | 4.19% |
| 8/6/1992 | 12.50% | 7.80% | 4.70% |
| 9/22/1992 | 12.00% | 7.71% | 4.29% |
| 9/28/1992 | 11.40% | 7.71% | 3.69% |
| 9/30/1992 | 11.75% | 7.70% | 4.05% |
| 10/2/1992 | 13.00% | 7.70% | 5.30% |
| 10/12/1992 | 12.20% | 7.70% | 4.50% |
| 10/16/1992 | 13.16% | 7.70% | 5.46% |
| 10/30/1992 | 11.75% | 7.71% | 4.04% |
| 11/3/1992 | 12.00% | 7.71% | 4.29% |
| 12/3/1992 | 11.85% | 7.68% | 4.17% |
| 12/15/1992 | 11.00% | 7.66% | 3.34% |
| 12/16/1992 | 11.90% | 7.66% | 4.24% |
| 12/16/1992 | 12.40% | 7.66% | 4.74% |
| 12/17/1992 | 12.00% | 7.66% | 4.34% |
| 12/22/1992 | 12.30% | 7.65% | 4.65% |
| 12/22/1992 | 12.40% | 7.65% | 4.75% |
| 12/29/1992 | 12.25% | 7.63% | 4.62% |
| 12/30/1992 | 12.00% | 7.63% | 4.37% |
| 12/31/1992 | 11.90% | 7.63% | 4.27% |
| 1/12/1993 | 12.00% | 7.61% | 4.39% |
| 1/21/1993 | 11.25% | 7.59% | 3.66% |
| 2/2/1993 | 11.40% | 7.56% | 3.84% |
| 2/15/1993 | 12.30% | 7.52% | 4.78% |
| 2/24/1993 | 11.90% | 7.49% | 4.41% |
| 2/26/1993 | 11.80% | 7.48% | 4.32% |
| 2/26/1993 | 12.20% | 7.48% | 4.72% |
| 4/23/1993 | 11.75% | 7.29% | 4.46% |
| 5/11/1993 | 11.75% | 7.25% | 4.50% |
| 5/14/1993 | 11.50% | 7.24% | 4.26% |
| 5/25/1993 | 11.50% | 7.23% | 4.27% |
| 5/28/1993 | 11.00% | 7.22% | 3.78% |
| 6/3/1993 | 12.00% | 7.21% | 4.79% |
| 6/16/1993 | 11.50% | 7.19% | 4.31% |
| 6/18/1993 | 12.10% | 7.18% | 4.92% |
| 6/25/1993 | 11.67% | 7.17% | 4.50% |
| 7/21/1993 | 11.38% | 7.10% | 4.28% |
| 7/23/1993 | 10.46% | 7.09% | 3.37% |
| 8/24/1993 | 11.50% | 6.96% | 4.54% |
| 9/21/1993 | 10.50% | 6.81% | 3.69% |
| 9/29/1993 | 11.47% | 6.77% | 4.70% |
| 9/30/1993 | 11.60% | 6.76% | 4.84% |
| 11/2/1993 | 10.80% | 6.60% | 4.20% |
| 11/12/1993 | 12.00% | 6.57% | 5.43% |
| 11/26/1993 | 11.00% | 6.52% | 4.48% |

I/A

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/14/1993 | 10.55% | 6.48% | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | 4.65% |
| 3/4/1994 | 11.00% | 6.35% | 4.65% |
| 4/25/1994 | 11.00% | 6.41% | 4.59% |
| 5/10/1994 | 11.75% | 6.45% | 5.30% |
| 5/13/1994 | 10.50% | 6.46% | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | 2.67% |
| 11/9/1994 | 10.85% | 7.39% | 3.46% |
| 11/9/1994 | 10.85% | 7.39% | 3.46% |
| 11/18/1994 | 11.20% | 7.45% | 3.75% |
| 11/22/1994 | 11.60% | 7.47% | 4.13% |
| 11/28/1994 | 11.06% | 7.49% | 3.57% |
| 12/8/1994 | 11.50% | 7.54% | 3.96% |
| 12/8/1994 | 11.70% | 7.54% | 4.16% |
| 12/14/1994 | 10.95% | 7.56% | 3.39% |
| 12/15/1994 | 11.50% | 7.57% | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | 4.20% |
| 3/9/1995 | 11.50% | 7.71% | 3.79% |
| 3/20/1995 | 12.00% | 7.72% | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | 3.88% |
| 4/6/1995 | 11.10% | 7.71% | 3.39% |
| 4/7/1995 | 11.00% | 7.71% | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | 3.55% |
| 6/9/1995 | 11.25% | 7.60% | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | 4.69% |
| 6/30/1995 | 11.10% | 7.52% | 3.58% |
| 9/11/1995 | 11.30% | 7.20% | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | 3.89% |
| 11/9/1995 | 11.38% | 6.90% | 4.48% |
| 11/9/1995 | 12.36% | 6.90% | 5.46% |
| 11/17/1995 | 11.00% | 6.86% | 4.14% |
| 12/4/1995 | 11.35% | 6.78% | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | 4.66% |
| 12/20/1995 | 11.60% | 6.70% | 4.90% |
| 12/27/1995 | 12.00% | 6.66% | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | 4.47% |
| 12/18/1996 | 11.75% | 6.83% | 4.92% |
| 12/31/1996 | 11.50% | 6.83% | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | 4.98% |
| 2/20/1997 | 11.80% | 6.82% | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | 6.36% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/2/1998 | 11.25% | 6.29% | 4.96% |
| 3/6/1998 | 10.75% | 6.27% | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | 7.00% |
| 1/22/2002 | 10.00% | 5.50% | 4.50% |
| 3/27/2002 | 10.10% | 5.45% | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | 7.32% |
| 2/28/2003 | 12.30% | 5.05% | 7.25% |
| 3/6/2003 | 10.75% | 5.03% | 5.72% |
| 3/7/2003 | 9.96% | 5.02% | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | 7.02% |
| 4/3/2003 | 12.00% | 4.96% | 7.04% |
| 4/15/2003 | 11.15% | 4.94% | 6.21% |
| 6/25/2003 | 10.75% | 4.79% | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | 4.96% |
| 7/25/2003 | 9.50% | 4.80% | 4.70% |
| 8/26/2003 | 10.50% | 4.83% | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | 5.56% |
| 1/13/2004 | 12.00% | 4.95% | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | 5.43% |
| 5/25/2004 | 10.25% | 5.08% | 5.17% |
| 5/27/2004 | 10.25% | 5.08% | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | 5.94% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/14/2004 | 10.97% | 5.07% | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | 6.43% |
| 12/29/2004 | 9.85% | 5.07% | 4.78% |
| 1/6/2005 | 10.70% | 5.08% | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | 6.07% |
| 3/24/2005 | 10.30% | 4.90% | 5.40% |
| 4/4/2005 | 10.00% | 4.88% | 5.12% |
| 4/7/2005 | 10.25% | 4.87% | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | 5.46% |
| 10/4/2005 | 10.75% | 4.54% | 6.21% |
| 12/12/2005 | 11.00% | 4.55% | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | 5.86% |
| 4/17/2006 | 10.20% | 4.61% | 5.59% |
| 4/26/2006 | 10.60% | 4.64% | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | 6.91% |
| 6/6/2006 | 10.00% | 4.74% | 5.26% |
| 6/27/2006 | 10.75% | 4.80% | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | 5.64% |
| 7/28/2006 | 10.05% | 4.86% | 5.19% |
| 8/23/2006 | 9.55% | 4.89% | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | 5.17% |
| 12/1/2006 | 10.25% | 4.95% | 5.30% |
| 12/1/2006 | 10.50% | 4.95% | 5.55% |
| 12/7/2006 | 10.75% | 4.95% | 5.80% |
| 12/21/2006 | 10.90% | 4.95% | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | 5.86% |
| 3/21/2007 | 11.35% | 4.87% | 6.48% |
| 3/22/2007 | 9.75% | 4.86% | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | 5.19% |
| 5/17/2007 | 10.25% | 4.81% | 5.44% |
| 5/17/2007 | 10.25% | 4.81% | 5.44% |
| 5/22/2007 | 10.20% | 4.80% | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | 5.34% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/20/2007 | 10.20% | 4.85% | 5.35% |
| 12/20/2007 | 11.00% | 4.85% | 6.15% |
| 12/28/2007 | 10.25% | 4.85% | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | 5.50% |
| 5/1/2008 | 10.70% | 4.59% | 6.11% |
| 5/19/2008 | 11.00% | 4.56% | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | 5.91% |
| 7/16/2008 | 9.40% | 4.52% | 4.88% |
| 7/30/2008 | 10.80% | 4.51% | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | 6.19% |
| 8/11/2008 | 10.25% | 4.51% | 5.74% |
| 8/26/2008 | 10.18% | 4.50% | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/30/2008 | 10.20% | 4.48% | 5.72% |
| 10/8/2008 | 10.15% | 4.46% | 5.69% |
| 11/13/2008 | 10.55% | 4.45% | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | 5.76% |
| 12/1/2008 | 10.25% | 4.40% | 5.85% |
| 12/23/2008 | 11.00% | 4.27% | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | 6.35% |
| 1/21/2009 | 10.50% | 4.12% | 6.38% |
| 1/21/2009 | 10.50% | 4.12% | 6.38% |
| 1/21/2009 | 10.50% | 4.12% | 6.38% |
| 1/27/2009 | 10.76% | 4.09% | 6.67% |
| 1/30/2009 | 10.50% | 4.08% | 6.42% |
| 2/4/2009 | 8.75% | 4.06% | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | 6.81% |
| 4/24/2009 | 10.00% | 3.79% | 6.21% |
| 4/30/2009 | 11.25% | 3.78% | 7.47% |
| 5/4/2009 | 10.74% | 3.77% | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | 6.24% |
| 6/24/2009 | 10.80% | 3.77% | 7.03% |
| 7/8/2009 | 10.63% | 3.77% | 6.86% |
| 7/17/2009 | 10.50% | 3.78% | 6.72% |
| 8/31/2009 | 10.25% | 3.82% | 6.43% |
| 10/14/2009 | 10.70% | 4.01% | 6.69% |
| 10/23/2009 | 10.88% | 4.06% | 6.82% |
| 11/2/2009 | 10.70% | 4.09% | 6.61% |
| 11/3/2009 | 10.70% | 4.10% | 6.60% |
| 11/24/2009 | 10.25% | 4.15% | 6.10% |
| 11/25/2009 | 10.75% | 4.16% | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | 6.32% |
| 12/7/2009 | 10.70% | 4.18% | 6.52% |
| 12/16/2009 | 10.90% | 4.21% | 6.69% |
| 12/16/2009 | 11.00% | 4.21% | 6.79% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | 6.52% |
| 1/11/2010 | 11.00% | 4.30% | 6.70% |
| 1/26/2010 | 10.13% | 4.35% | 5.78% |
| 1/27/2010 | 10.40% | 4.35% | 6.05% |
| 1/27/2010 | 10.40% | 4.35% | 6.05% |
| 1/27/2010 | 10.70% | 4.35% | 6.35% |
| 2/9/2010 | 9.80% | 4.38% | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | 6.09% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/5/2010 | 10.50% | 4.41% | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | 5.42% |
| 8/25/2010 | 9.90% | 4.37% | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | 6.37% |
| 9/16/2010 | 10.00% | 4.33% | 5.67% |
| 9/16/2010 | 10.00% | 4.33% | 5.67% |
| 9/30/2010 | 9.75% | 4.29% | 5.46% |
| 10/14/2010 | 10.35% | 4.24% | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | 6.18% |
| 11/4/2010 | 10.70% | 4.20% | 6.50% |
| 11/19/2010 | 10.20% | 4.18% | 6.02% |
| 11/22/2010 | 10.00% | 4.18% | 5.82% |
| 12/1/2010 | 10.13% | 4.16% | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | 6.29% |
| 12/17/2010 | 10.00% | 4.15% | 5.85% |
| 12/20/2010 | 10.60% | 4.15% | 6.45% |
| 12/21/2010 | 10.30% | 4.14% | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | 6.01% |
| 1/31/2011 | 9.60% | 4.12% | 5.48% |
| 2/3/2011 | 10.00% | 4.12% | 5.88% |
| 2/25/2011 | 10.00% | 4.14% | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | 6.51% |
| 4/26/2011 | 9.67% | 4.23% | 5.44% |
| 4/27/2011 | 10.40% | 4.24% | 6.16% |
| 5/4/2011 | 10.00% | 4.24% | 5.76% |
| 5/4/2011 | 10.00% | 4.24% | 5.76% |
| 5/24/2011 | 10.50% | 4.27% | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | 5.63% |
| 7/13/2011 | 10.20% | 4.36% | 5.84% |
| 8/1/2011 | 9.20% | 4.39% | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | 5.62% |
| 8/12/2011 | 10.35% | 4.37% | 5.98% |
| 8/19/2011 | 10.25% | 4.36% | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 12/14/2011 | 10.00% | 3.80% | 6.20% |
| 12/14/2011 | 10.30% | 3.80% | 6.50% |
| 12/20/2011 | 10.20% | 3.76% | 6.44% |
| 12/21/2011 | 10.20% | 3.76% | 6.44% |
| 12/22/2011 | 9.90% | 3.75% | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | 6.93% |

I/A

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 1/27/2012 | 10.50% | 3.56% | 6.94% |
| 2/15/2012 | 10.20% | 3.47% | 6.73% |
| 2/23/2012 | 9.90% | 3.44% | 6.46% |
| 2/27/2012 | 10.25% | 3.43% | 6.82% |
| 2/29/2012 | 10.40% | 3.41% | 6.99% |
| 3/29/2012 | 10.37% | 3.32% | 7.05% |
| 4/4/2012 | 10.00% | 3.30% | 6.70% |
| 4/26/2012 | 10.00% | 3.21% | 6.79% |
| 5/2/2012 | 10.00% | 3.18% | 6.82% |
| 5/7/2012 | 9.80% | 3.17% | 6.63% |
| 5/15/2012 | 10.00% | 3.14% | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | 6.94% |
| 6/7/2012 | 10.30% | 3.08% | 7.22% |
| 6/14/2012 | 9.40% | 3.06% | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | 7.34% |
| 6/18/2012 | 9.60% | 3.06% | 6.54% |
| 6/19/2012 | 9.25% | 3.05% | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | 6.96% |
| 7/9/2012 | 10.20% | 3.03% | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | 6.86% |
| 9/19/2012 | 9.80% | 2.94% | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | 7.58% |
| 12/21/2012 | 10.20% | 2.87% | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | 6.94% |
| 1/9/2013 | 9.70% | 2.85% | 6.85% |
| 1/9/2013 | 9.70% | 2.85% | 6.85% |
| 1/9/2013 | 9.70% | 2.85% | 6.85% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | 6.77% |
| 7/12/2013 | 9.36% | 3.07% | 6.29% |
| 8/8/2013 | 9.83% | 3.14% | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | 5.99% |
| 9/11/2013 | 10.20% | 3.26% | 6.94% |
| 9/11/2013 | 10.25% | 3.26% | 6.99% |
| 9/24/2013 | 10.20% | 3.31% | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | 6.72% |
| 12/9/2013 | 8.72% | 3.48% | 5.24% |
| 12/9/2013 | 9.75% | 3.48% | 6.27% |
| 12/13/2013 | 9.75% | 3.50% | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | 5.99% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/17/2013 | 10.95% | 3.51% | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | 5.96% |
| 2/20/2014 | 9.20% | 3.68% | 5.52% |
| 2/26/2014 | 9.75% | 3.69% | 6.06% |
| 3/17/2014 | 9.55% | 3.72% | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | 6.73% |
| 6/30/2014 | 9.55% | 3.64% | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | 6.30% |
| 8/20/2014 | 9.75% | 3.57% | 6.18% |
| 8/25/2014 | 9.60% | 3.56% | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | 6.74% |
| 10/9/2014 | 9.80% | 3.45% | 6.35% |
| 11/6/2014 | 9.56% | 3.37% | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | 6.85% |
| 11/26/2014 | 9.70% | 3.33% | 6.37% |
| 11/26/2014 | 10.20% | 3.33% | 6.87% |
| 12/4/2014 | 9.68% | 3.31% | 6.37% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/11/2014 | 10.07% | 3.29% | 6.78% |
| 12/12/2014 | 10.20% | 3.28% | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | 6.77% |
| 3/25/2015 | 9.50% | 2.96% | 6.54% |
| 3/26/2015 | 9.72% | 2.95% | 6.77% |
| 4/23/2015 | 10.20% | 2.87% | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | 6.87% |
| 8/24/2016 | 9.75% | 2.62% | 7.13% |
| 9/1/2016 | 9.50% | 2.59% | 6.91% |
| 9/8/2016 | 10.00% | 2.58% | 7.42% |
| 9/28/2016 | 9.58% | 2.54% | 7.04% |
| 9/30/2016 | 9.90% | 2.53% | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | 7.07% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/14/2016 | 9.10% | 2.53% | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | 7.50% |
| 2/15/2017 | 9.60% | 2.62% | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | 6.82% |
| 4/4/2017 | 10.25% | 2.71% | 7.54% |
| 4/12/2017 | 9.40% | 2.74% | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 12/5/2017 | 9.50% | 2.88% | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | 6.64% |
| 12/20/2017 | 9.58% | 2.86% | 6.72% |
| 12/21/2017 | 9.10% | 2.85% | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | 6.86% |

I/A



| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 2/27/2019 | 9.75% | 3.12% | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | 6.53% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | 6.81% |
| 8/12/2019 | 9.60% | 2.90% | 6.70% |
| | | Average: | 4.68% |
| | | No. of Cases: | 1,594 |

Expected Earnings Analysis

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| | | Expected ROE | Shares Outstanding | | | Adjustment | Adjusted |
| Company | Ticker | 2022-2024 | 2019 | 2022-2024 | % Increase | Factor | ROE |
| ALLETE, Inc. | ALE | 9.0% | 51.75 | 51.75 | 0.00% | 1.000 | 9.00% |
| Alliant Energy Corporation | LNT | 10.0% | 240.00 | 250.00 | 0.82% | 1.004 | 10.04% |
| Ameren Corporation | AEE | 10.5% | 246.50 | 255.00 | 0.68% | 1.003 | 10.54% |
| American Electric Power Company, Inc. | AEP | 10.5% | 494.65 | 518.00 | 0.93% | 1.005 | 10.55% |
| Avangrid, Inc. | AGR | 6.0% | 309.00 | 309.00 | 0.00% | 1.000 | 6.00% |
| CMS Energy Corporation | CMS | 14.0% | 285.00 | 297.00 | 0.83% | 1.004 | 14.06% |
| DTE Energy Company | DTE | 10.5% | 192.00 | 200.00 | 0.82% | 1.004 | 10.54% |
| Evergy, Inc | EVRG | 8.5% | 225.00 | 212.00 | -1.18% | 0.994 | 8.45% |
| Hawaiian Electric Industries, Inc. | HE | 10.0% | 109.00 | 113.00 | 0.72% | 1.004 | 10.04% |
| NextEra Energy, Inc. | NEE | 13.5% | 535.00 | 535.00 | 0.00% | 1.000 | 13.50% |
| NorthWestern Corporation | NWE | 9.0% | 50.50 | 51.10 | 0.24% | 1.001 | 9.01% |
| OGE Energy Corp. | OGE | 11.5% | 200.00 | 200.00 | 0.00% | 1.000 | 11.50% |
| Otter Tail Corporation | OTTR | 10.5% | 39.75 | 41.75 | 0.99% | 1.005 | 10.55% |
| Pinnacle West Capital Corporation | PNW | 10.5% | 113.00 | 115.00 | 0.35% | 1.002 | 10.52% |
| PNM Resources, Inc. | PNM | 10.0% | 79.65 | 85.00 | 1.31% | 1.007 | 10.07% |
| Portland General Electric Company | POR | 9.0% | 89.40 | 90.00 | 0.13% | 1.001 | 9.01% |
| Southern Company | SO | 12.5% | 1050.00 | 1090.00 | 0.75% | 1.004 | 12.55% |
| WEC Energy Group, Inc. | WEC | 12.0% | 315.50 | 315.50 | 0.00% | 1.000 | 12.00% |
| Xcel Energy Inc. | XEL | 11.0% | 516.00 | 525.00 | 0.35% | 1.002 | 11.02% |
| | | | | | | Median | 10.54% |
| | | | | | | Mean | 10.47% |

Notes:

[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals = ([3] / [2])^(1/5)-1
[5] Equals (2 x (1 + [4])) / (2 + [4])
[6] Equals [1] x [5]

Flotation Cost Adjustment

Two most recent open market common stock issuances per company, if available

| Company | Date | [1] Shares Issued | [2] Offering Price | [3] Underwriting Discount | [4] Offering Expense | [5] Net Proceeds Per Share | [6] Total Flotation Costs | [7] Gross Equity Issue Before Costs | [8] Net Proceeds | [9] Flotation Cost Percentage |
|---|---|---|---|---|---|---|---|---|---|---|
| Duke Energy Corporation | 3/6/2018 | 21,275,000 | $74.07 | $0.0000 | $450,000 | $74.05 | $450,000 | $1,575,881,800 | $1,575,431,800 | 0.029% |
| Duke Energy Corporation | 3/2/2016 | 10,637,500 | $72.00 | $2.1600 | $400,000 | $69.80 | $23,377,000 | $765,900,000 | $742,523,000 | 3.052% |
| ALLETE, Inc. | 2/27/2014 | 3,220,000 | $49.75 | $1.7413 | $450,000 | $47.87 | $6,056,825 | $160,195,000 | $154,138,175 | 3.781% |
| ALLETE, Inc. | 5/25/2001 | 7,475,000 | $23.68 | $0.9472 | $350,000 | $22.69 | $7,430,320 | $177,008,000 | $169,577,680 | 4.198% |
| Alliant Energy Corporation | 7/1/2003 | 17,250,000 | $19.25 | $0.7700 | $370,000 | $18.46 | $13,652,500 | $332,062,500 | $318,410,000 | 4.111% |
| Alliant Energy Corporation | 11/8/2001 | 9,775,000 | $28.00 | $1.0500 | $425,000 | $26.91 | $10,688,750 | $273,700,000 | $263,011,250 | 3.905% |
| Ameren Corp. | 9/9/2009 | 21,850,000 | $25.25 | $0.7575 | $450,000 | $24.47 | $17,001,375 | $551,712,500 | $534,711,125 | 3.082% |
| Ameren Corp. | 6/30/2004 | 10,925,000 | $42.00 | $1.2600 | $400,000 | $40.70 | $14,165,500 | $458,850,000 | $444,684,500 | 3.087% |
| American Electric Power Company, Inc. | 4/1/2009 | 69,000,000 | $24.50 | $0.7350 | $400,000 | $23.76 | $51,115,000 | $1,690,500,000 | $1,639,385,000 | 3.024% |
| American Electric Power Company, Inc. | 2/27/2003 | 57,500,000 | $20.95 | $0.6285 | $550,000 | $20.31 | $36,688,750 | $1,204,625,000 | $1,167,936,250 | 3.046% |
| Avangrid, Inc. | 9/26/2013 | 5,750,000 | $37.25 | $1.3038 | $250,000 | $35.90 | $7,746,563 | $214,187,500 | $206,440,938 | 3.617% |
| Avangrid, Inc. | 9/16/2010 | 20,355,000 | $25.75 | $1.0944 | $325,000 | $24.64 | $22,601,003 | $524,141,250 | $501,540,247 | 4.312% |
| CMS Energy Corporation | 3/30/2005 | 23,000,000 | $12.25 | $0.4288 | $325,000 | $11.81 | $10,187,400 | $281,750,000 | $271,562,600 | 3.616% |
| CMS Energy Corporation | 10/7/2004 | 32,775,000 | $9.10 | $0.3185 | $325,000 | $8.77 | $10,763,838 | $298,252,500 | $287,488,663 | 3.609% |
| DTE Energy Company | 6/19/2002 | 6,325,000 | $43.25 | $1.4056 | $250,000 | $41.80 | $9,140,420 | $273,556,250 | $264,415,830 | 3.341% |
| Hawaiian Electric Industries, Inc | 3/19/2013 | 7,000,000 | $26.75 | $1.0031 | $450,000 | $25.68 | $7,471,840 | $187,250,000 | $179,778,160 | 3.990% |
| Hawaiian Electric Industries, Inc | 12/2/2008 | 5,000,000 | $23.00 | $0.8625 | $300,000 | $22.08 | $4,612,500 | $115,000,000 | $110,387,500 | 4.011% |
| NextEra Energy, Inc. | 11/1/2016 | 13,800,000 | $124.00 | $0.0000 | $750,000 | $123.95 | $750,000 | $1,711,200,000 | $1,710,450,000 | 0.044% |
| NextEra Energy, Inc. | 11/18/2013 | 11,100,000 | $88.03 | $0.0000 | $750,000 | $87.96 | $750,000 | $977,133,000 | $976,383,000 | 0.077% |
| NorthWestern Corporation | 9/29/2015 | 1,100,000 | $51.81 | $1.3300 | $1,000,000 | $49.57 | $2,463,000 | $56,991,000 | $54,528,000 | 4.322% |
| NorthWestern Corporation | 11/5/2014 | 7,766,990 | $51.50 | $1.8025 | $1,000,000 | $49.57 | $14,999,999 | $399,999,985 | $384,999,986 | 3.750% |
| OGE Energy Corp. | 8/21/2003 | 5,324,074 | $21.60 | $0.7900 | $325,000 | $20.75 | $4,531,018 | $114,999,998 | $110,468,980 | 3.940% |
| Otter Tail Corporation | 9/18/2008 | 5,175,000 | $30.00 | $1.0875 | $400,000 | $28.84 | $6,027,813 | $155,250,000 | $149,222,188 | 3.883% |
| Otter Tail Corporation | 12/7/2004 | 3,335,000 | $25.45 | $0.9500 | $300,000 | $24.41 | $3,468,250 | $84,875,750 | $81,407,500 | 4.086% |
| Pinnacle West Capital Corporation | 4/8/2010 | 6,900,000 | $38.00 | $1.3300 | $190,000 | $36.64 | $9,367,000 | $262,200,000 | $252,833,000 | 3.572% |
| Pinnacle West Capital Corporation | 4/27/2005 | 6,095,000 | $42.00 | $1.3650 | $250,000 | $40.59 | $8,569,675 | $255,990,000 | $247,420,325 | 3.348% |
| PNM Resources, Inc. | 12/6/2006 | 5,750,000 | $30.79 | $1.0780 | $250,000 | $29.67 | $6,448,500 | $177,042,500 | $170,594,000 | 3.642% |
| PNM Resources, Inc. | 3/23/2005 | 3,910,000 | $26.76 | $0.8697 | $200,000 | $25.84 | $3,600,527 | $104,631,600 | $101,031,073 | 3.441% |
| Portland General Electric Company | 6/11/2013 | 12,765,000 | $29.50 | $0.9588 | $600,000 | $28.49 | $12,838,444 | $376,567,500 | $363,729,056 | 3.409% |
| Portland General Electric Company | 3/5/2009 | 12,477,500 | $14.10 | $0.4935 | $375,000 | $13.58 | $6,532,646 | $175,932,750 | $169,400,104 | 3.713% |
| Southern Company | 8/16/2016 | 32,500,000 | $49.30 | $1.6600 | $557,000 | $47.62 | $54,507,000 | $1,602,250,000 | $1,547,743,000 | 3.402% |
| Southern Company | 5/5/2016 | 18,300,000 | $48.60 | $2.0200 | $395,000 | $46.56 | $37,361,000 | $889,380,000 | $852,019,000 | 4.201% |
| WEC Energy Group | 11/16/2005 | 5,290,000 | $53.70 | $1.7450 | $0 | $51.96 | $9,231,050 | $284,073,000 | $274,841,950 | 3.250% |
| WEC Energy Group | 11/20/2003 | 4,025,000 | $43.00 | $1.5050 | $0 | $41.50 | $6,057,625 | $173,075,000 | $167,017,375 | 3.500% |
| Xcel Energy Inc. | 8/3/2010 | 21,850,000 | $21.50 | $0.6450 | $600,000 | $20.83 | $14,693,250 | $469,775,000 | $455,081,750 | 3.128% |
| Xcel Energy Inc. | 9/9/2008 | 17,250,000 | $20.25 | $0.1500 | $600,000 | $20.07 | $3,187,500 | $349,312,500 | $346,125,000 | 0.913% |
| Mean | | | | | | | $12,737,052 | $491,812,552 | | |

WEIGHTED AVERAGE FLOTATION COSTS: 2.590% [10]

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

| | | [11] | [12] | [13] | [14] | [15] | [16] | [17] | [18] | [19] | [20] | [21] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Expected Dividend Yield | | | | | | | |
| Company | Ticker | Annualized Dividend | Average Stock Price | Dividend Yield | Current | Adjusted for Flot. Costs | Zacks Earnings Growth | First Call Earnings Growth | Value Line Earnings Growth | Average Earnings Growth | DCF k(e) | Flotation Adjusted DCF k(e) |
| ALLETE, Inc. | ALE | $2.35 | $85.94 | 2.73% | 2.82% | 2.89% | 7.20% | 6.00% | 5.00% | 6.07% | 8.88% | 8.96% |
| Alliant Energy Corporation | LNT | $1.42 | $50.33 | 2.82% | 2.90% | 2.98% | 5.50% | 5.05% | 6.50% | 5.68% | 8.59% | 8.66% |
| Ameren Corporation | AEE | $1.90 | $76.23 | 2.49% | 2.57% | 2.63% | 6.50% | 4.90% | 6.50% | 5.97% | 8.53% | 8.60% |
| American Electric Power Company, Inc. | AEP | $2.68 | $89.81 | 2.98% | 3.06% | 3.14% | 5.70% | 6.10% | 4.00% | 5.27% | 8.33% | 8.41% |
| Avangrid, Inc. | AGR | $1.76 | $49.78 | 3.54% | 3.68% | 3.78% | 7.50% | 6.60% | 10.00% | 8.03% | 11.71% | 11.81% |
| CMS Energy Corporation | CMS | $1.53 | $59.04 | 2.59% | 2.68% | 2.75% | 6.40% | 7.14% | 7.00% | 6.85% | 9.53% | 9.60% |
| DTE Energy Company | DTE | $3.78 | $129.04 | 2.93% | 3.01% | 3.09% | 6.00% | 4.45% | 5.50% | 5.32% | 8.32% | 8.40% |
| Evergy, Inc | EVRG | $1.90 | $61.53 | 3.09% | 3.19% | 3.27% | 6.60% | 6.15% | NMF | 6.38% | 9.56% | 9.65% |
| Hawaiian Electric Industries, Inc. | HE | $1.28 | $44.44 | 2.88% | 2.96% | 3.04% | 5.60% | 6.10% | 4.50% | 5.40% | 8.36% | 8.44% |
| NextEra Energy, Inc. | NEE | $5.00 | $211.08 | 2.37% | 2.47% | 2.54% | 8.00% | 7.99% | 10.50% | 8.83% | 11.30% | 11.37% |
| NorthWestern Corporation | NWE | $2.30 | $70.90 | 3.24% | 3.29% | 3.38% | 2.60% | 3.24% | 3.00% | 2.95% | 6.24% | 6.33% |
| OGE Energy Corp. | OGE | $1.46 | $42.87 | 3.41% | 3.48% | 3.58% | 4.40% | 3.10% | 6.50% | 4.67% | 8.15% | 8.24% |
| Otter Tail Corporation | OTTR | $1.40 | $52.32 | 2.68% | 2.77% | 2.84% | 7.00% | 9.00% | 5.00% | 7.00% | 9.77% | 9.84% |
| Pinnacle West Capital Corporation | PNW | $2.95 | $93.12 | 3.17% | 3.26% | 3.34% | 6.10% | 5.05% | 5.50% | 5.55% | 8.81% | 8.89% |
| PNM Resources, Inc. | PNM | $1.16 | $50.01 | 2.32% | 2.39% | 2.46% | 5.50% | 6.18% | 7.00% | 6.23% | 8.62% | 8.68% |
| Portland General Electric Company | POR | $1.54 | $55.14 | 2.79% | 2.86% | 2.93% | 4.80% | 4.80% | 4.50% | 4.70% | 7.56% | 7.63% |
| Southern Company | SO | $2.48 | $56.51 | 4.39% | 4.46% | 4.58% | 5.00% | 1.37% | 3.50% | 3.29% | 7.75% | 7.87% |
| WEC Energy Group, Inc. | WEC | $2.36 | $87.27 | 2.70% | 2.78% | 2.86% | 5.90% | 5.91% | 6.00% | 5.94% | 8.72% | 8.80% |
| Xcel Energy Inc. | XEL | $1.62 | $60.88 | 2.66% | 2.73% | 2.81% | 4.90% | 5.80% | 5.50% | 5.40% | 8.13% | 8.21% |
| PROXY GROUP MEAN | | | | | | | | | | | 8.78% | 8.86% |

| | | |
|---|---|---|
| DCF Result Adjusted For Flotation Costs: | 8.86% | |
| DCF Result Unadjusted For Flotation Costs: | 8.78% | |
| Difference (Flotation Cost Adjustment): | 0.08% | [22] |

Notes:

The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (1 - flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.

[1] Source: SEC Form 424B
[2] Source: SEC Form 424B
[3] Source: SEC Form 424B
[4] Source: SEC Form 424B
[5] Equals [8] / [1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Equals average [6] / average [7]
[11] Source: Bloomberg Professional
[12] Source: Bloomberg Professional
[13] Equals [11] / [12]
[14] Equals [3] x (1 + 0.5 x [19])
[15] Equals [4] / (1 - 0.0091)
[16] Source: Zacks
[17] Source: Yahoo! Finance
[18] Source: Value Line
[19] Equals Average([16], [17], [18])
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals average [21] - average [20]

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $61.34 | 4.03% | 4.15% | NA | 7.00% | 5.50% | 6.25% | 9.64% | 10.40% | 11.17% |
| Alliant Energy Corporation | LNT | $1.52 | $49.05 | 3.10% | 3.19% | 5.50% | 5.65% | 6.50% | 5.88% | 8.68% | 9.07% | 9.70% |
| Ameren Corporation | AEE | $1.98 | $73.95 | 2.68% | 2.75% | 5.90% | 4.90% | 6.00% | 5.60% | 7.64% | 8.35% | 8.76% |
| American Electric Power Company, Inc. | AEP | $2.80 | $82.61 | 3.39% | 3.49% | 5.80% | 6.15% | 5.00% | 5.65% | 8.47% | 9.14% | 9.64% |
| Avangrid, Inc. | AGR | $1.76 | $44.42 | 3.96% | 4.11% | 6.80% | 6.30% | 8.50% | 7.20% | 10.39% | 11.31% | 12.63% |
| Avista Corporation | AVA | $1.62 | $43.56 | 3.72% | 3.81% | 5.40% | 6.10% | 3.50% | 5.00% | 7.28% | 8.81% | 9.93% |
| CMS Energy Corporation | CMS | $1.63 | $59.21 | 2.75% | 2.85% | 7.10% | 7.50% | 7.50% | 7.37% | 9.95% | 10.22% | 10.36% |
| DTE Energy Company | DTE | $4.05 | $96.10 | 4.21% | 4.33% | 6.00% | 6.00% | 5.00% | 5.67% | 9.32% | 10.00% | 10.34% |
| Evergy, Inc | EVRG | $2.02 | $57.44 | 3.52% | 3.59% | 5.00% | 3.90% | NMF | 4.45% | 7.49% | 8.04% | 8.60% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $42.72 | 3.09% | 3.14% | 3.50% | 3.30% | 2.50% | 3.10% | 5.63% | 6.24% | 6.64% |
| NextEra Energy, Inc. | NEE | $5.60 | $228.30 | 2.45% | 2.56% | 7.60% | 7.59% | 10.00% | 8.40% | 10.14% | 10.95% | 12.58% |
| NorthWestern Corporation | NWE | $2.40 | $60.71 | 3.95% | 4.01% | 3.30% | 3.79% | 2.00% | 3.03% | 5.99% | 7.04% | 7.82% |
| OGE Energy Corp. | OGE | $1.55 | $30.64 | 5.06% | 5.14% | 3.40% | 1.70% | 4.50% | 3.20% | 6.80% | 8.34% | 9.67% |
| Otter Tail Corporation | OTTR | $1.48 | $43.20 | 3.43% | 3.55% | NA | 9.00% | 5.00% | 7.00% | 8.51% | 10.55% | 12.58% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $77.40 | 4.04% | 4.13% | 4.40% | 4.62% | 4.00% | 4.34% | 8.12% | 8.47% | 8.76% |
| PNM Resources, Inc. | PNM | $1.23 | $39.99 | 3.08% | 3.17% | 5.90% | 6.30% | 7.00% | 6.40% | 9.07% | 9.57% | 10.18% |
| Portland General Electric Company | POR | $1.54 | $48.75 | 3.16% | 3.23% | 4.70% | 4.70% | 4.50% | 4.63% | 7.73% | 7.87% | 7.93% |
| Southern Company | SO | $2.48 | $54.86 | 4.52% | 4.60% | 4.00% | 2.10% | 4.00% | 3.37% | 6.67% | 7.96% | 8.61% |
| WEC Energy Group, Inc. | WEC | $2.53 | $92.21 | 2.74% | 2.83% | 6.20% | 6.23% | 6.00% | 6.14% | 8.83% | 8.97% | 9.06% |
| Xcel Energy Inc. | XEL | $1.72 | $61.55 | 2.79% | 2.88% | 6.00% | 6.10% | 5.50% | 5.87% | 8.37% | 8.74% | 8.98% |
| Proxy Group Mean | | | | 3.48% | 3.58% | 5.36% | 5.45% | 5.39% | 5.43% | 8.24% | 9.00% | 9.70% |
| Proxy Group Median | | | | 3.41% | 3.52% | 5.65% | 6.05% | 5.00% | 5.66% | 8.42% | 8.89% | 9.66% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of April 17, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $74.17 | 3.33% | 3.43% | NA | 7.00% | 5.50% | 6.25% | 8.92% | 9.68% | 10.45% |
| Alliant Energy Corporation | LNT | $1.52 | $53.94 | 2.82% | 2.90% | 5.50% | 5.65% | 6.50% | 5.88% | 8.40% | 8.78% | 9.41% |
| Ameren Corporation | AEE | $1.98 | $78.00 | 2.54% | 2.61% | 5.90% | 4.90% | 6.00% | 5.60% | 7.50% | 8.21% | 8.61% |
| American Electric Power Company, Inc. | AEP | $2.80 | $92.55 | 3.03% | 3.11% | 5.80% | 6.15% | 5.00% | 5.65% | 8.10% | 8.76% | 9.27% |
| Avangrid, Inc. | AGR | $1.76 | $49.41 | 3.56% | 3.69% | 6.80% | 6.30% | 8.50% | 7.20% | 9.97% | 10.89% | 12.21% |
| Avista | AVA | $1.62 | $47.39 | 3.42% | 3.50% | 5.40% | 6.10% | 3.50% | 5.00% | 6.98% | 8.50% | 9.62% |
| CMS Energy Corporation | CMS | $1.63 | $63.06 | 2.58% | 2.68% | 7.10% | 7.50% | 7.50% | 7.37% | 9.78% | 10.05% | 10.18% |
| DTE Energy Company | DTE | $4.05 | $118.20 | 3.43% | 3.52% | 6.00% | 6.00% | 5.00% | 5.67% | 8.51% | 9.19% | 9.53% |
| Evergy, Inc | EVRG | $2.02 | $64.35 | 3.14% | 3.21% | 5.00% | 3.90% | NMF | 4.45% | 7.10% | 7.66% | 8.22% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $45.68 | 2.89% | 2.93% | 3.50% | 3.30% | 2.50% | 3.10% | 5.43% | 6.03% | 6.44% |
| NextEra Energy, Inc. | NEE | $5.60 | $246.91 | 2.27% | 2.36% | 7.60% | 7.59% | 10.00% | 8.40% | 9.94% | 10.76% | 12.38% |
| NorthWestern Corporation | NWE | $2.40 | $69.83 | 3.44% | 3.49% | 3.30% | 3.79% | 2.00% | 3.03% | 5.47% | 6.52% | 7.29% |
| OGE Energy Corp. | OGE | $1.55 | $39.69 | 3.90% | 3.97% | 3.40% | 1.70% | 4.50% | 3.20% | 5.64% | 7.17% | 8.49% |
| Otter Tail Corporation | OTTR | $1.48 | $49.38 | 3.00% | 3.10% | NA | 9.00% | 5.00% | 7.00% | 8.07% | 10.10% | 12.13% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $88.33 | 3.54% | 3.62% | 4.40% | 4.62% | 4.00% | 4.34% | 7.61% | 7.96% | 8.25% |
| PNM Resources, Inc. | PNM | $1.23 | $47.94 | 2.57% | 2.65% | 5.90% | 6.30% | 7.00% | 6.40% | 8.54% | 9.05% | 9.66% |
| Portland General Electric Company | POR | $1.54 | $55.12 | 2.79% | 2.86% | 4.70% | 4.70% | 4.50% | 4.63% | 7.36% | 7.49% | 7.56% |
| Southern Company | SO | $2.48 | $62.17 | 3.99% | 4.06% | 4.00% | 2.10% | 4.00% | 3.37% | 6.13% | 7.42% | 8.07% |
| WEC Energy Group, Inc. | WEC | $2.53 | $94.83 | 2.67% | 2.75% | 6.20% | 6.23% | 6.00% | 6.14% | 8.75% | 8.89% | 8.98% |
| Xcel Energy Inc. | XEL | $1.72 | $64.44 | 2.67% | 2.75% | 6.00% | 6.10% | 5.50% | 5.87% | 8.24% | 8.61% | 8.85% |
| Proxy Group Mean | | | | 3.08% | 3.16% | 5.36% | 5.45% | 5.39% | 5.43% | 7.82% | 8.59% | 9.28% |
| Proxy Group Median | | | | 3.01% | 3.11% | 5.65% | 6.05% | 5.00% | 5.66% | 8.09% | 8.69% | 9.12% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of April 17, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $79.42 | 3.11% | 3.21% | NA | 7.00% | 5.50% | 6.25% | 8.70% | 9.46% | 10.22% |
| Alliant Energy Corporation | LNT | $1.52 | $53.24 | 2.86% | 2.94% | 5.50% | 5.65% | 6.50% | 5.88% | 8.43% | 8.82% | 9.45% |
| Ameren Corporation | AEE | $1.98 | $77.25 | 2.56% | 2.63% | 5.90% | 4.90% | 6.00% | 5.60% | 7.53% | 8.23% | 8.64% |
| American Electric Power Company, Inc. | AEP | $2.80 | $92.13 | 3.04% | 3.13% | 5.80% | 6.15% | 5.00% | 5.65% | 8.12% | 8.78% | 9.28% |
| Avangrid, Inc. | AGR | $1.76 | $49.69 | 3.54% | 3.67% | 6.80% | 6.30% | 8.50% | 7.20% | 9.95% | 10.87% | 12.19% |
| Avista | AVA | $1.62 | $47.33 | 3.42% | 3.51% | 5.40% | 6.10% | 3.50% | 5.00% | 6.98% | 8.51% | 9.63% |
| CMS Energy Corporation | CMS | $1.63 | $62.61 | 2.60% | 2.70% | 7.10% | 7.50% | 7.50% | 7.37% | 9.80% | 10.07% | 10.20% |
| DTE Energy Company | DTE | $4.05 | $123.14 | 3.29% | 3.38% | 6.00% | 6.00% | 5.00% | 5.67% | 8.37% | 9.05% | 9.39% |
| Evergy, Inc | EVRG | $2.02 | $64.23 | 3.14% | 3.21% | 5.00% | 3.90% | NMF | 4.45% | 7.11% | 7.66% | 8.22% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $45.06 | 2.93% | 2.97% | 3.50% | 3.30% | 2.50% | 3.10% | 5.47% | 6.07% | 6.48% |
| NextEra Energy, Inc. | NEE | $5.60 | $236.68 | 2.37% | 2.47% | 7.60% | 7.59% | 10.00% | 8.40% | 10.05% | 10.86% | 12.48% |
| NorthWestern Corporation | NWE | $2.40 | $71.02 | 3.38% | 3.43% | 3.30% | 3.79% | 2.00% | 3.03% | 5.41% | 6.46% | 7.23% |
| OGE Energy Corp. | OGE | $1.55 | $41.46 | 3.74% | 3.80% | 3.40% | 1.70% | 4.50% | 3.20% | 5.47% | 7.00% | 8.32% |
| Otter Tail Corporation | OTTR | $1.48 | $50.78 | 2.91% | 3.02% | NA | 9.00% | 5.00% | 7.00% | 7.99% | 10.02% | 12.05% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $90.47 | 3.46% | 3.53% | 4.40% | 4.62% | 4.00% | 4.34% | 7.53% | 7.87% | 8.16% |
| PNM Resources, Inc. | PNM | $1.23 | $49.16 | 2.50% | 2.58% | 5.90% | 6.30% | 7.00% | 6.40% | 8.48% | 8.98% | 9.59% |
| Portland General Electric Company | POR | $1.54 | $55.56 | 2.77% | 2.84% | 4.70% | 4.70% | 4.50% | 4.63% | 7.33% | 7.47% | 7.54% |
| Southern Company | SO | $2.48 | $61.34 | 4.04% | 4.11% | 4.00% | 2.10% | 4.00% | 3.37% | 6.19% | 7.48% | 8.12% |
| WEC Energy Group, Inc. | WEC | $2.53 | $93.29 | 2.71% | 2.80% | 6.20% | 6.23% | 6.00% | 6.14% | 8.79% | 8.94% | 9.03% |
| Xcel Energy Inc. | XEL | $1.72 | $63.61 | 2.70% | 2.78% | 6.00% | 6.10% | 5.50% | 5.87% | 8.28% | 8.65% | 8.89% |
| Proxy Group Mean | | | | 3.05% | 3.14% | 5.36% | 5.45% | 5.39% | 5.43% | 7.80% | 8.56% | 9.26% |
| Proxy Group Median | | | | 2.98% | 3.07% | 5.65% | 6.05% | 5.00% | 5.66% | 8.05% | 8.71% | 9.15% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of April 17, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

| [1] | [2] | [3] |
|---|---|---|
| S&P 500 Est. Required Market Return | Current 30-Year Treasury (30-day average) | Implied Market Risk Premium |
| 12.93% | 1.37% | 11.56% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 24,632.77 | N/A | 0.91% | N/A | N/A | N/A |
| American Airlines Group Inc | AAL | 4,929.50 | 0.02% | 2.59% | -12.30% | -9.87% | -0.0020% |
| Advance Auto Parts Inc | AAP | 8,211.97 | 0.03% | 0.63% | 11.15% | 11.82% | 0.0039% |
| Apple Inc | AAPL | 1,237,385.74 | 5.01% | 1.14% | 10.98% | 12.18% | 0.6096% |
| AbbVie Inc | ABBV | 123,228.35 | 0.50% | 5.77% | 1.53% | 7.35% | 0.0366% |
| AmerisourceBergen Corp | ABC | 18,363.49 | 0.07% | 1.87% | 12.35% | 14.33% | 0.0106% |
| ABIOMED Inc | ABMD | 7,481.30 | N/A | 0.00% | N/A | N/A | N/A |
| Abbott Laboratories | ABT | 169,307.23 | 0.69% | 1.48% | 8.10% | 9.64% | 0.0660% |
| Accenture PLC | ACN | 111,705.15 | 0.45% | 1.82% | 10.50% | 12.42% | 0.0561% |
| Adobe Inc | ADBE | 165,792.49 | 0.67% | 0.00% | 17.67% | 17.67% | 0.1185% |
| Analog Devices Inc | ADI | 37,853.03 | 0.15% | 2.33% | 12.15% | 14.63% | 0.0224% |
| Archer-Daniels-Midland Co | ADM | 20,722.56 | 0.08% | 3.89% | 8.80% | 12.86% | 0.0108% |
| Automatic Data Processing Inc | ADP | 60,911.89 | 0.25% | 2.48% | 16.00% | 18.68% | 0.0460% |
| Alliance Data Systems Corp | ADS | 1,803.18 | 0.01% | 23.67% | -0.40% | 23.22% | 0.0017% |
| Autodesk Inc | ADSK | 39,720.21 | 0.16% | 0.00% | 33.95% | 33.95% | 0.0546% |
| Ameren Corp | AEE | 19,203.56 | 0.08% | 2.60% | 6.45% | 9.13% | 0.0071% |
| American Electric Power Co Inc | AEP | 42,743.65 | 0.17% | 3.27% | 6.91% | 10.29% | 0.0178% |
| AES Corp/VA | AES | 8,721.76 | 0.04% | 4.45% | 7.81% | 12.43% | 0.0044% |
| Aflac Inc | AFL | 26,357.22 | 0.11% | 3.12% | 0.67% | 3.80% | 0.0041% |
| Allergan PLC | AGN | 61,523.38 | N/A | 1.60% | N/A | N/A | N/A |
| American International Group Inc | AIG | 21,101.61 | 0.09% | 5.31% | 15.85% | 21.58% | 0.0184% |
| Apartment Investment & Management Co | AIV | 5,830.63 | 0.02% | 4.21% | 2.35% | 6.61% | 0.0016% |
| Assurant Inc | AIZ | 6,329.95 | N/A | 2.40% | N/A | N/A | N/A |
| Arthur J Gallagher & Co | AJG | 15,851.19 | 0.06% | 2.14% | 10.44% | 12.69% | 0.0081% |
| Akamai Technologies Inc | AKAM | 17,054.25 | 0.07% | 0.00% | 11.80% | 11.80% | 0.0081% |
| Albemarle Corp | ALB | 6,535.41 | 0.03% | 2.47% | 8.00% | 10.57% | 0.0028% |
| Align Technology Inc | ALGN | 15,200.43 | 0.06% | 0.00% | 21.00% | 21.00% | 0.0129% |
| Alaska Air Group Inc | ALK | 3,668.96 | 0.01% | 1.23% | -14.87% | -13.73% | -0.0020% |
| Allstate Corp/The | ALL | 33,197.25 | 0.13% | 2.00% | 7.37% | 9.45% | 0.0127% |
| Allegion plc | ALLE | 9,003.27 | 0.04% | 1.06% | 3.01% | 4.09% | 0.0015% |
| Alexion Pharmaceuticals Inc | ALXN | 22,879.43 | 0.09% | 0.00% | 10.92% | 10.92% | 0.0101% |
| Applied Materials Inc | AMAT | 48,853.83 | 0.20% | 1.63% | 13.16% | 14.90% | 0.0294% |
| Amcor PLC | AMCR | 14,083.54 | 0.06% | 5.39% | 8.10% | 13.71% | 0.0078% |
| Advanced Micro Devices Inc | AMD | 66,270.24 | 0.27% | 0.00% | 20.33% | 20.33% | 0.0545% |
| AMETEK Inc | AME | 18,406.26 | 0.07% | 0.79% | 7.90% | 8.72% | 0.0065% |
| Amgen Inc | AMGN | 138,106.56 | 0.56% | 2.68% | 8.06% | 10.85% | 0.0606% |
| Ameriprise Financial Inc | AMP | 13,643.36 | 0.06% | 3.70% | 3.90% | 7.67% | 0.0042% |
| American Tower Corp | AMT | 112,663.38 | 0.46% | 1.78% | 16.80% | 18.72% | 0.0853% |
| Amazon.com Inc | AMZN | 1,183,996.93 | 4.79% | 0.00% | 34.85% | 34.85% | 1.6695% |
| Arista Networks Inc | ANET | 15,889.85 | 0.06% | 0.00% | 15.80% | 15.80% | 0.0102% |
| ANSYS Inc | ANSS | 22,584.66 | 0.09% | 0.00% | 11.50% | 11.50% | 0.0105% |
| Anthem Inc | ANTM | 67,527.40 | 0.27% | 1.42% | 12.76% | 14.27% | 0.0390% |
| Aon PLC | AON | 44,136.65 | 0.18% | 0.99% | 11.30% | 12.35% | 0.0220% |
| AO Smith Corp | AOS | 6,655.17 | 0.03% | 2.49% | 8.00% | 10.59% | 0.0029% |
| Apache Corp | APA | 3,204.28 | 0.01% | 3.89% | -18.00% | -14.46% | -0.0019% |
| Air Products & Chemicals Inc | APD | 48,880.28 | 0.20% | 2.31% | 11.35% | 13.80% | 0.0273% |
| Amphenol Corp | APH | 24,916.09 | 0.10% | 1.17% | 6.02% | 7.22% | 0.0073% |
| Aptiv PLC | APTV | 16,313.59 | 0.07% | 0.98% | 8.39% | 9.42% | 0.0062% |
| Alexandria Real Estate Equities Inc | ARE | 19,599.32 | 0.08% | 2.70% | 3.33% | 6.08% | 0.0048% |
| Atmos Energy Corp | ATO | 13,539.40 | 0.05% | 2.08% | 7.35% | 9.50% | 0.0052% |
| Activision Blizzard Inc | ATVI | 51,445.54 | 0.21% | 0.59% | 8.59% | 9.20% | 0.0192% |
| AvalonBay Communities Inc | AVB | 23,976.97 | 0.10% | 3.73% | 6.68% | 10.53% | 0.0102% |
| Broadcom Inc | AVGO | 106,296.52 | 0.43% | 4.89% | 5.40% | 10.42% | 0.0448% |
| Avery Dennison Corp | AVY | 9,109.25 | 0.04% | 2.16% | 7.00% | 9.24% | 0.0034% |
| American Water Works Co Inc | AWK | 23,851.14 | 0.10% | 1.62% | 8.19% | 9.88% | 0.0095% |
| American Express Co | AXP | 70,416.95 | 0.28% | 2.02% | 4.85% | 6.92% | 0.0197% |
| AutoZone Inc | AZO | 23,160.94 | 0.09% | 0.00% | 9.63% | 9.63% | 0.0090% |
| Boeing Co/The | BA | 86,890.78 | 0.35% | 1.33% | 12.90% | 14.32% | 0.0503% |
| Bank of America Corp | BAC | 201,965.35 | 0.82% | 3.18% | 9.25% | 12.58% | 0.1028% |
| Baxter International Inc | BAX | 47,144.81 | 0.19% | 1.01% | 11.95% | 13.02% | 0.0248% |
| Best Buy Co Inc | BBY | 18,128.24 | 0.07% | 3.21% | 7.00% | 10.33% | 0.0076% |
| Becton Dickinson and Co | BDX | 70,884.66 | 0.29% | 1.37% | 11.40% | 12.85% | 0.0369% |
| Franklin Resources Inc | BEN | 8,119.31 | 0.03% | 6.63% | -9.73% | -3.42% | -0.0011% |
| Brown-Forman Corp | BF/B | 29,746.50 | 0.12% | 1.06% | 2.77% | 3.84% | 0.0046% |
| Biogen Inc | BIIB | 59,625.63 | 0.24% | 0.00% | 0.16% | 0.16% | 0.0004% |
| Bank of New York Mellon Corp/The | BK | 33,106.71 | 0.13% | 3.35% | 4.15% | 7.57% | 0.0101% |
| Booking Holdings Inc | BKNG | 60,396.59 | 0.24% | 0.00% | 12.43% | 12.43% | 0.0304% |
| Baker Hughes Co | BKR | 13,436.13 | 0.05% | 5.55% | 16.89% | 22.91% | 0.0125% |
| BlackRock Inc | BLK | 74,024.18 | 0.30% | 3.04% | 3.84% | 6.95% | 0.0208% |
| Ball Corp | BLL | 22,870.21 | 0.09% | 0.77% | 8.53% | 9.34% | 0.0086% |
| Bristol-Myers Squibb Co | BMY | 137,105.28 | 0.55% | 2.97% | 11.38% | 14.52% | 0.0805% |
| Broadridge Financial Solutions Inc | BR | 12,621.39 | 0.05% | 1.98% | 7.10% | 9.15% | 0.0047% |
| Berkshire Hathaway Inc | BRK/B | 463,136.35 | 1.87% | 0.00% | -3.10% | -3.10% | -0.0581% |
| Boston Scientific Corp | BSX | 53,575.36 | 0.22% | 0.00% | 11.03% | 11.03% | 0.0239% |
| BorgWarner Inc | BWA | 5,576.88 | 0.02% | 2.59% | 9.38% | 12.10% | 0.0027% |
| Boston Properties Inc | BXP | 14,814.11 | 0.06% | 4.17% | 3.29% | 7.53% | 0.0045% |
| Citigroup Inc | C | 94,617.81 | 0.38% | 4.53% | -1.53% | 2.97% | 0.0114% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Conagra Brands Inc | CAG | 16,356.02 | 0.07% | 2.53% | 8.40% | 11.04% | 0.0073% |
| Cardinal Health Inc | CAH | 14,948.07 | 0.06% | 3.94% | 4.73% | 8.76% | 0.0053% |
| Carrier Global Corp | CARR | 11,901.02 | N/A | 0.00% | N/A | N/A | N/A |
| Caterpillar Inc | CAT | 63,974.61 | 0.26% | 3.68% | 7.83% | 11.66% | 0.0302% |
| Chubb Ltd | CB | 53,682.13 | 0.22% | 2.59% | 10.00% | 12.72% | 0.0276% |
| Cboe Global Markets Inc | CBOE | 11,191.42 | 0.05% | 1.46% | 10.00% | 11.53% | 0.0052% |
| CBRE Group Inc | CBRE | 14,960.66 | 0.06% | 0.00% | 8.45% | 8.45% | 0.0051% |
| Crown Castle International Corp | CCI | 69,618.00 | 0.28% | 2.92% | 16.00% | 19.15% | 0.0539% |
| Carnival Corp | CCL | 9,310.71 | 0.04% | 11.42% | -2.76% | 8.50% | 0.0032% |
| Cadence Design Systems Inc | CDNS | 22,087.53 | 0.09% | 0.00% | 9.84% | 9.84% | 0.0088% |
| CDW Corp/DE | CDW | 15,480.49 | 0.06% | 1.37% | 13.10% | 14.56% | 0.0091% |
| Celanese Corp | CE | 9,345.30 | 0.04% | 3.42% | 5.32% | 8.83% | 0.0033% |
| Cerner Corp | CERN | 21,300.24 | 0.09% | 0.64% | 14.47% | 15.15% | 0.0131% |
| CF Industries Holdings Inc | CF | 6,048.32 | 0.02% | 4.27% | 6.00% | 10.40% | 0.0025% |
| Citizens Financial Group Inc | CFG | 8,476.27 | 0.03% | 7.71% | -38.61% | -32.39% | -0.0111% |
| Church & Dwight Co Inc | CHD | 18,076.85 | 0.07% | 1.31% | 7.82% | 9.18% | 0.0067% |
| CH Robinson Worldwide Inc | CHRW | 9,749.35 | 0.04% | 2.79% | 10.00% | 12.93% | 0.0051% |
| Charter Communications Inc | CHTR | 132,774.53 | 0.54% | 0.00% | 24.58% | 24.58% | 0.1320% |
| Cigna Corp | CI | 72,200.73 | 0.29% | 0.03% | 11.02% | 11.05% | 0.0323% |
| Cincinnati Financial Corp | CINF | 13,920.70 | N/A | 3.00% | N/A | N/A | N/A |
| Colgate-Palmolive Co | CL | 62,953.78 | 0.25% | 2.48% | 5.24% | 7.78% | 0.0198% |
| Clorox Co/The | CLX | 24,206.77 | 0.10% | 2.18% | 4.40% | 6.63% | 0.0065% |
| Comerica Inc | CMA | 4,210.31 | 0.02% | 9.21% | -4.66% | 4.34% | 0.0007% |
| Comcast Corp | CMCSA | 173,379.56 | 0.70% | 2.41% | 8.78% | 11.29% | 0.0792% |
| CME Group Inc | CME | 68,691.86 | 0.28% | 3.25% | 8.27% | 11.65% | 0.0324% |
| Chipotle Mexican Grill Inc | CMG | 22,809.94 | 0.09% | 0.00% | 13.20% | 13.20% | 0.0122% |
| Cummins Inc | CMI | 22,096.89 | 0.09% | 3.55% | 0.31% | 3.87% | 0.0035% |
| CMS Energy Corp | CMS | 17,953.42 | 0.07% | 2.57% | 7.17% | 9.84% | 0.0071% |
| Centene Corp | CNC | 41,833.74 | 0.17% | 0.00% | 14.77% | 14.77% | 0.0250% |
| CenterPoint Energy Inc | CNP | 8,308.22 | 0.03% | 4.94% | -1.04% | 3.87% | 0.0013% |
| Capital One Financial Corp | COF | 24,988.93 | 0.10% | 2.98% | 7.17% | 10.26% | 0.0104% |
| Cabot Oil & Gas Corp | COG | 8,354.14 | 0.03% | 1.94% | 1.10% | 3.05% | 0.0010% |
| Cooper Cos Inc/The | COO | 16,334.05 | 0.07% | 0.02% | 8.93% | 8.95% | 0.0059% |
| ConocoPhillips | COP | 37,970.08 | 0.15% | 4.79% | -13.00% | -8.52% | -0.0131% |
| Costco Wholesale Corp | COST | 140,387.10 | 0.57% | 0.85% | 8.07% | 8.96% | 0.0509% |
| Coty Inc | COTY | 4,373.76 | 0.02% | 6.26% | 2.89% | 9.24% | 0.0016% |
| Campbell Soup Co | CPB | 15,189.82 | 0.06% | 2.80% | 7.48% | 10.38% | 0.0064% |
| Capri Holdings Ltd | CPRI | 1,931.29 | 0.01% | 0.00% | -0.89% | -0.89% | -0.0001% |
| Copart Inc | CPRT | 16,850.17 | N/A | 0.00% | N/A | N/A | N/A |
| salesforce.com Inc | CRM | 145,544.90 | 0.59% | 0.00% | 19.15% | 19.15% | 0.1128% |
| Cisco Systems Inc | CSCO | 180,152.59 | 0.73% | 3.33% | 5.42% | 8.84% | 0.0644% |
| CSX Corp | CSX | 48,377.54 | 0.20% | 1.62% | 10.48% | 12.19% | 0.0239% |
| Cintas Corp | CTAS | 21,242.89 | N/A | 1.25% | N/A | N/A | N/A |
| CenturyLink Inc | CTL | 11,253.48 | 0.05% | 9.76% | 0.63% | 10.42% | 0.0047% |
| Cognizant Technology Solutions Corp | CTSH | 29,522.16 | 0.12% | 1.61% | 10.38% | 12.07% | 0.0144% |
| Corteva Inc | CTVA | 19,114.22 | 0.08% | 1.96% | 11.58% | 13.65% | 0.0106% |
| Citrix Systems Inc | CTXS | 18,568.21 | 0.08% | 0.93% | 9.17% | 10.14% | 0.0076% |
| CVS Health Corp | CVS | 82,722.29 | 0.33% | 3.16% | 8.30% | 11.59% | 0.0388% |
| Chevron Corp | CVX | 162,744.53 | N/A | 5.85% | N/A | N/A | N/A |
| Concho Resources Inc | CXO | 10,216.96 | 0.04% | 1.53% | 4.60% | 6.16% | 0.0025% |
| Dominion Energy Inc | D | 68,327.64 | 0.28% | 4.64% | 4.90% | 9.65% | 0.0267% |
| Delta Air Lines Inc | DAL | 15,535.08 | 0.06% | 1.65% | -15.05% | -13.53% | -0.0085% |
| DuPont de Nemours Inc | DD | 28,148.37 | 0.11% | 3.21% | 2.22% | 5.46% | 0.0062% |
| Deere & Co | DE | 43,423.83 | 0.18% | 2.30% | 1.10% | 3.41% | 0.0060% |
| Discover Financial Services | DFS | 10,730.58 | 0.04% | 5.16% | 4.36% | 9.64% | 0.0042% |
| Dollar General Corp | DG | 45,803.41 | 0.19% | 0.78% | 10.53% | 11.35% | 0.0210% |
| Quest Diagnostics Inc | DGX | 12,755.09 | 0.05% | 2.37% | 5.60% | 8.03% | 0.0041% |
| DR Horton Inc | DHI | 14,610.59 | 0.06% | 1.72% | 10.45% | 12.26% | 0.0072% |
| Danaher Corp | DHR | 109,085.00 | 0.44% | 0.46% | 11.21% | 11.70% | 0.0516% |
| Walt Disney Co/The | DIS | 192,513.92 | 0.78% | 1.74% | 18.26% | 20.16% | 0.1570% |
| Discovery Inc | DISCA | 15,187.87 | 0.06% | 0.00% | -0.63% | -0.63% | -0.0004% |
| DISH Network Corp | DISH | 11,779.12 | 0.05% | 0.00% | -0.08% | -0.08% | 0.0000% |
| Digital Realty Trust Inc | DLR | 40,003.87 | 0.16% | 3.07% | 18.50% | 21.85% | 0.0354% |
| Dollar Tree Inc | DLTR | 19,354.55 | 0.08% | 0.00% | 8.45% | 8.45% | 0.0066% |
| Dover Corp | DOV | 12,749.99 | 0.05% | 2.27% | 10.70% | 13.09% | 0.0068% |
| Dow Inc | DOW | 24,820.36 | 0.10% | 8.54% | 3.33% | 12.01% | 0.0121% |
| Duke Realty Corp | DRE | 12,862.53 | 0.05% | 2.68% | 4.11% | 6.84% | 0.0036% |
| Darden Restaurants Inc | DRI | 7,654.17 | 0.03% | 4.05% | 6.89% | 11.07% | 0.0034% |
| DTE Energy Co | DTE | 20,334.32 | 0.08% | 3.84% | 6.03% | 9.98% | 0.0082% |
| Duke Energy Corp | DUK | 66,135.98 | 0.27% | 4.30% | 4.86% | 9.26% | 0.0248% |
| DaVita Inc | DVA | 9,816.90 | 0.04% | 0.00% | 15.18% | 15.18% | 0.0060% |
| Devon Energy Corp | DVN | 3,530.34 | 0.01% | 4.61% | 7.47% | 12.25% | 0.0018% |
| DXC Technology Co | DXC | 3,889.54 | 0.02% | 5.38% | -7.39% | -2.21% | -0.0003% |
| Electronic Arts Inc | EA | 33,356.00 | 0.13% | 0.00% | 8.09% | 8.09% | 0.0109% |
| eBay Inc | EBAY | 29,817.21 | 0.12% | 1.69% | 11.23% | 13.02% | 0.0157% |
| Ecolab Inc | ECL | 51,688.47 | 0.21% | 1.08% | 10.70% | 11.83% | 0.0247% |
| Consolidated Edison Inc | ED | 29,910.90 | 0.12% | 3.42% | 3.46% | 6.94% | 0.0084% |
| Equifax Inc | EFX | 15,514.54 | 0.06% | 1.25% | 7.69% | 8.98% | 0.0056% |
| Edison International | EIX | 22,503.84 | 0.09% | 4.10% | 4.81% | 9.01% | 0.0082% |
| Estee Lauder Cos Inc/The | EL | 62,653.48 | 0.25% | 1.03% | 11.33% | 12.42% | 0.0315% |
| Eastman Chemical Co | EMN | 7,487.77 | 0.03% | 4.79% | 5.27% | 10.18% | 0.0031% |
| Emerson Electric Co | EMR | 30,922.45 | 0.13% | 3.93% | 6.37% | 10.43% | 0.0130% |
| EOG Resources Inc | EOG | 24,353.18 | 0.10% | 3.40% | -4.97% | -1.66% | -0.0016% |
| Equinix Inc | EQIX | 59,379.23 | 0.24% | 1.53% | 21.46% | 23.15% | 0.0556% |
| Equity Residential | EQR | 25,960.38 | N/A | 3.43% | N/A | N/A | N/A |
| Eversource Energy | ES | 30,245.21 | 0.12% | 2.48% | 6.33% | 8.88% | 0.0109% |
| Essex Property Trust Inc | ESS | 17,262.75 | 0.07% | 3.15% | 6.30% | 9.55% | 0.0067% |
| E*TRADE Financial Corp | ETFC | 8,812.23 | 0.04% | 1.46% | 3.38% | 4.86% | 0.0017% |
| Eaton Corp PLC | ETN | 32,610.49 | 0.13% | 3.63% | 9.33% | 13.13% | 0.0173% |
| Entergy Corp | ETR | 20,336.60 | 0.08% | 3.70% | 2.85% | 6.59% | 0.0054% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Evergy Inc | EVRG | 13,821.67 | 0.06% | 3.35% | 5.63% | 9.08% | 0.0051% |
| Edwards Lifesciences Corp | EW | 47,355.31 | 0.19% | 0.00% | 13.18% | 13.18% | 0.0253% |
| Exelon Corp | EXC | 37,437.86 | 0.15% | 3.97% | 1.19% | 5.18% | 0.0079% |
| Expeditors International of Washington I | EXPD | 12,051.52 | 0.05% | 1.46% | 9.70% | 11.23% | 0.0055% |
| Expedia Group Inc | EXPE | 8,850.11 | 0.04% | 1.69% | 13.67% | 15.47% | 0.0055% |
| Extra Space Storage Inc | EXR | 12,055.88 | 0.05% | 3.92% | 4.17% | 8.17% | 0.0040% |
| Ford Motor Co | F | 20,360.64 | 0.08% | 6.74% | 11.67% | 18.80% | 0.0155% |
| Diamondback Energy Inc | FANG | 4,989.13 | 0.02% | 4.50% | 11.96% | 16.73% | 0.0034% |
| Fastenal Co | FAST | 20,581.38 | 0.08% | 2.74% | 13.85% | 16.78% | 0.0140% |
| Facebook Inc | FB | 510,974.40 | 2.07% | 0.00% | 20.64% | 20.64% | 0.4266% |
| Fortune Brands Home & Security Inc | FBHS | 6,510.31 | 0.03% | 2.06% | 5.63% | 7.75% | 0.0020% |
| Freeport-McMoRan Inc | FCX | 12,101.11 | 0.05% | 1.63% | 138.40% | 141.16% | 0.0691% |
| FedEx Corp | FDX | 32,617.03 | 0.13% | 2.09% | 14.06% | 16.29% | 0.0215% |
| FirstEnergy Corp | FE | 25,033.36 | 0.10% | 3.38% | 1.61% | 5.02% | 0.0051% |
| F5 Networks Inc | FFIV | 7,546.40 | 0.03% | 0.00% | 5.20% | 5.20% | 0.0016% |
| Fidelity National Information Services I | FIS | 79,045.62 | 0.32% | 1.15% | 18.45% | 19.71% | 0.0630% |
| Fiserv Inc | FISV | 68,059.71 | 0.28% | 0.00% | 14.77% | 14.77% | 0.0407% |
| Fifth Third Bancorp | FITB | 11,826.14 | 0.05% | 6.57% | 1.80% | 8.43% | 0.0040% |
| FLIR Systems Inc | FLIR | 4,591.66 | 0.02% | 2.14% | 10.40% | 12.65% | 0.0023% |
| Flowserve Corp | FLS | 3,226.79 | N/A | 3.19% | N/A | N/A | N/A |
| FleetCor Technologies Inc | FLT | 19,101.08 | 0.08% | 0.04% | 11.05% | 11.09% | 0.0086% |
| FMC Corp | FMC | 11,144.83 | 0.05% | 1.99% | 9.80% | 11.88% | 0.0054% |
| Fox Corp | FOXA | 16,139.63 | 0.07% | 1.69% | -9.57% | -7.97% | -0.0052% |
| First Republic Bank/CA | FRC | 17,132.19 | 0.07% | 0.79% | 6.49% | 7.31% | 0.0051% |
| Federal Realty Investment Trust | FRT | 5,698.92 | 0.02% | 5.61% | 6.08% | 11.86% | 0.0027% |
| TechnipFMC PLC | FTI | 3,630.17 | 0.01% | 6.40% | 3.00% | 9.50% | 0.0014% |
| Fortinet Inc | FTNT | 19,487.26 | 0.08% | 0.00% | 16.20% | 16.20% | 0.0128% |
| Fortive Corp | FTV | 20,306.03 | 0.08% | 0.51% | 5.90% | 6.42% | 0.0053% |
| General Dynamics Corp | GD | 40,104.52 | 0.16% | 3.13% | 7.18% | 10.42% | 0.0169% |
| General Electric Co | GE | 59,790.61 | 0.24% | 0.58% | 6.33% | 6.94% | 0.0168% |
| Gilead Sciences Inc | GILD | 105,744.68 | 0.43% | 3.23% | 0.80% | 4.04% | 0.0173% |
| General Mills Inc | GIS | 36,774.45 | 0.15% | 3.23% | 5.87% | 9.20% | 0.0137% |
| Globe Life Inc | GL | 8,296.43 | 0.03% | 0.93% | 5.95% | 6.91% | 0.0023% |
| Corning Inc | GLW | 15,801.49 | 0.06% | 4.35% | 9.40% | 13.96% | 0.0089% |
| General Motors Co | GM | 32,123.97 | 0.13% | 6.14% | 13.36% | 19.90% | 0.0259% |
| Alphabet Inc | GOOGL | 880,586.70 | 3.56% | 0.00% | 16.09% | 16.09% | 0.5734% |
| Genuine Parts Co | GPC | 10,852.74 | 0.04% | 4.20% | 2.58% | 6.83% | 0.0030% |
| Global Payments Inc | GPN | 46,483.90 | 0.19% | 0.38% | 20.52% | 20.95% | 0.0394% |
| Gap Inc/The | GPS | 3,111.54 | 0.01% | 10.92% | 8.50% | 19.89% | 0.0025% |
| Garmin Ltd | GRMN | 15,657.34 | 0.06% | 2.94% | 7.03% | 10.08% | 0.0064% |
| Goldman Sachs Group Inc/The | GS | 65,776.61 | 0.27% | 2.76% | 5.13% | 7.95% | 0.0212% |
| WW Grainger Inc | GWW | 15,040.27 | 0.06% | 2.14% | 11.50% | 13.76% | 0.0084% |
| Halliburton Co | HAL | 6,620.00 | N/A | 9.50% | N/A | N/A | N/A |
| Hasbro Inc | HAS | 10,302.92 | 0.04% | 3.69% | 10.61% | 14.50% | 0.0060% |
| Huntington Bancshares Inc/OH | HBAN | 8,245.19 | 0.03% | 7.51% | -9.95% | -2.81% | -0.0009% |
| Hanesbrands Inc | HBI | 3,296.11 | 0.01% | 6.55% | 2.89% | 9.53% | 0.0013% |
| HCA Healthcare Inc | HCA | 39,147.30 | 0.16% | 1.59% | 10.25% | 11.92% | 0.0189% |
| Home Depot Inc/The | HD | 224,941.40 | 0.91% | 2.80% | 9.49% | 12.43% | 0.1131% |
| Hess Corp | HES | 11,399.76 | N/A | 2.67% | N/A | N/A | N/A |
| HollyFrontier Corp | HFC | 4,374.09 | 0.02% | 5.20% | 1.40% | 6.64% | 0.0012% |
| Hartford Financial Services Group Inc/Th | HIG | 14,322.43 | 0.06% | 3.30% | 12.00% | 15.49% | 0.0090% |
| Huntington Ingalls Industries Inc | HII | 7,980.25 | 0.03% | 2.19% | 40.00% | 42.63% | 0.0138% |
| Hilton Worldwide Holdings Inc | HLT | 20,980.60 | 0.08% | 0.17% | 1.56% | 1.73% | 0.0015% |
| Harley-Davidson Inc | HOG | 2,963.17 | 0.01% | 6.81% | 7.70% | 14.77% | 0.0018% |
| Hologic Inc | HOLX | 11,566.11 | 0.05% | 0.00% | 11.10% | 11.10% | 0.0052% |
| Honeywell International Inc | HON | 97,831.89 | 0.40% | 2.60% | 6.19% | 8.87% | 0.0351% |
| Helmerich & Payne Inc | HP | 1,931.49 | N/A | 12.68% | N/A | N/A | N/A |
| Hewlett Packard Enterprise Co | HPE | 12,509.80 | 0.05% | 4.97% | 2.05% | 7.08% | 0.0036% |
| HP Inc | HPQ | 22,189.94 | 0.09% | 4.54% | 3.57% | 8.19% | 0.0074% |
| H&R Block Inc | HRB | 2,763.95 | 0.01% | 7.26% | 10.00% | 17.63% | 0.0020% |
| Hormel Foods Corp | HRL | 27,163.07 | 0.11% | 1.83% | 4.63% | 6.50% | 0.0071% |
| Henry Schein Inc | HSIC | 7,657.43 | 0.03% | 0.00% | 1.13% | 1.13% | 0.0003% |
| Host Hotels & Resorts Inc | HST | 8,025.88 | 0.03% | 6.11% | -2.30% | 3.74% | 0.0012% |
| Hershey Co/The | HSY | 30,655.63 | 0.12% | 2.18% | 7.70% | 9.96% | 0.0124% |
| Humana Inc | HUM | 49,360.15 | 0.20% | 0.65% | 11.97% | 12.66% | 0.0253% |
| Howmet Aerospace Inc | HWM | 5,078.45 | 0.02% | 0.00% | 51.10% | 51.10% | 0.0105% |
| International Business Machines Corp | IBM | 106,715.57 | 0.43% | 5.57% | 2.66% | 8.30% | 0.0359% |
| Intercontinental Exchange Inc | ICE | 49,642.04 | 0.20% | 1.31% | 9.77% | 11.14% | 0.0224% |
| IDEXX Laboratories Inc | IDXX | 22,598.24 | 0.09% | 0.00% | 17.29% | 17.29% | 0.0158% |
| IDEX Corp | IEX | 11,644.02 | 0.05% | 1.36% | 11.60% | 13.04% | 0.0061% |
| International Flavors & Fragrances Inc | IFF | 13,363.09 | 0.05% | 2.40% | 7.47% | 9.95% | 0.0054% |
| Illumina Inc | ILMN | 46,446.16 | 0.19% | 0.00% | 18.80% | 18.80% | 0.0353% |
| Incyte Corp | INCY | 21,677.55 | 0.09% | 0.00% | 20.20% | 20.20% | 0.0177% |
| IHS Markit Ltd | INFO | 26,795.22 | 0.11% | 0.71% | 12.20% | 12.95% | 0.0140% |
| Intel Corp | INTC | 258,372.40 | 1.05% | 2.18% | 6.94% | 9.19% | 0.0961% |
| Intuit Inc | INTU | 69,123.48 | 0.28% | 0.78% | 16.20% | 17.05% | 0.0477% |
| International Paper Co | IP | 12,530.77 | 0.05% | 6.44% | -30.30% | -24.84% | -0.0126% |
| Interpublic Group of Cos Inc/The | IPG | 5,864.96 | 0.02% | 6.35% | 0.13% | 6.48% | 0.0015% |
| IPG Photonics Corp | IPGP | 6,326.58 | N/A | 0.00% | N/A | N/A | N/A |
| IQVIA Holdings Inc | IQV | 25,368.87 | 0.10% | 0.00% | 11.85% | 11.85% | 0.0122% |
| Ingersoll Rand Inc | IR | 11,141.61 | 0.05% | 0.41% | 9.40% | 9.83% | 0.0044% |
| Iron Mountain Inc | IRM | 7,193.85 | 0.03% | 9.97% | 6.70% | 17.01% | 0.0049% |
| Intuitive Surgical Inc | ISRG | 61,041.18 | 0.25% | 0.00% | 7.87% | 7.87% | 0.0194% |
| Gartner Inc | IT | 9,441.21 | 0.04% | 0.00% | 10.82% | 10.82% | 0.0041% |
| Illinois Tool Works Inc | ITW | 50,351.92 | 0.20% | 2.60% | 5.65% | 8.32% | 0.0170% |
| Invesco Ltd | IVZ | 4,112.61 | 0.02% | 13.68% | -8.63% | 4.46% | 0.0007% |
| Jacobs Engineering Group Inc | J | 11,202.82 | 0.05% | 0.89% | 12.69% | 13.63% | 0.0062% |
| JB Hunt Transport Services Inc | JBHT | 11,431.34 | 0.05% | 1.00% | 11.70% | 12.76% | 0.0059% |
| Johnson Controls International plc | JCI | 22,569.96 | 0.09% | 3.66% | 9.67% | 13.50% | 0.0123% |
| Jack Henry & Associates Inc | JKHY | 13,016.25 | 0.05% | 0.97% | 12.10% | 13.13% | 0.0069% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Johnson & Johnson | JNJ | 400,778.27 | 1.62% | 2.62% | 5.85% | 8.55% | 0.1386% |
| Juniper Networks Inc | JNPR | 7,470.94 | 0.03% | 3.52% | 8.70% | 12.38% | 0.0037% |
| JPMorgan Chase & Co | JPM | 289,969.40 | 1.17% | 3.82% | 5.70% | 9.63% | 0.1130% |
| Nordstrom Inc | JWN | 2,939.31 | 0.01% | 3.98% | 6.00% | 10.10% | 0.0012% |
| Kellogg Co | K | 22,269.26 | 0.09% | 3.58% | 3.22% | 6.86% | 0.0062% |
| KeyCorp | KEY | 10,543.20 | 0.04% | 6.85% | 3.36% | 10.33% | 0.0044% |
| Keysight Technologies Inc | KEYS | 17,959.97 | 0.07% | 0.00% | 20.00% | 20.00% | 0.0145% |
| Kraft Heinz Co/The | KHC | 35,834.13 | 0.14% | 5.35% | -0.21% | 5.14% | 0.0075% |
| Kimco Realty Corp | KIM | 3,857.98 | 0.02% | 12.15% | 4.72% | 17.16% | 0.0027% |
| KLA Corp | KLAC | 25,273.25 | 0.10% | 2.10% | 11.04% | 13.26% | 0.0136% |
| Kimberly-Clark Corp | KMB | 48,466.87 | 0.20% | 3.00% | 4.51% | 7.57% | 0.0149% |
| Kinder Morgan Inc | KMI | 33,861.06 | 0.14% | 8.02% | 5.60% | 13.85% | 0.0190% |
| CarMax Inc | KMX | 10,636.17 | 0.04% | 0.00% | 11.64% | 11.64% | 0.0050% |
| Coca-Cola Co/The | KO | 206,340.88 | 0.83% | 3.44% | 4.66% | 8.18% | 0.0683% |
| Kroger Co/The | KR | 24,838.09 | 0.10% | 2.06% | 5.25% | 7.37% | 0.0074% |
| Kohl's Corp | KSS | 2,868.96 | 0.01% | 13.46% | 8.00% | 22.00% | 0.0026% |
| Kansas City Southern | KSU | 13,242.02 | 0.05% | 1.12% | 11.00% | 12.18% | 0.0065% |
| Loews Corp | L | 10,232.55 | N/A | 0.00% | N/A | N/A | N/A |
| L Brands Inc | LB | 3,810.63 | 0.02% | 6.71% | 11.50% | 18.60% | 0.0029% |
| Leidos Holdings Inc | LDOS | 14,082.58 | 0.06% | 1.40% | 9.93% | 11.39% | 0.0065% |
| Leggett & Platt Inc | LEG | 3,820.68 | N/A | 5.68% | N/A | N/A | N/A |
| Lennar Corp | LEN | 13,021.50 | 0.05% | 0.77% | 9.66% | 10.46% | 0.0055% |
| Laboratory Corp of America Holdings | LH | 14,421.79 | 0.06% | 0.00% | 5.12% | 5.12% | 0.0030% |
| L3Harris Technologies Inc | LHX | 44,138.38 | 0.18% | 1.64% | 16.72% | 18.50% | 0.0330% |
| Linde PLC | LIN | 100,250.82 | 0.41% | 2.02% | 9.50% | 11.62% | 0.0471% |
| LKQ Corp | LKQ | 6,441.51 | 0.03% | 0.00% | 14.20% | 14.20% | 0.0037% |
| Eli Lilly & Co | LLY | 150,532.58 | 0.61% | 1.89% | 10.88% | 12.87% | 0.0784% |
| Lockheed Martin Corp | LMT | 113,172.98 | 0.46% | 2.46% | 7.76% | 10.31% | 0.0472% |
| Lincoln National Corp | LNC | 5,794.72 | 0.02% | 5.55% | 9.00% | 14.80% | 0.0035% |
| Alliant Energy Corp | LNT | 12,965.24 | 0.05% | 2.86% | 5.83% | 8.78% | 0.0046% |
| Lowe's Cos Inc | LOW | 73,305.51 | 0.30% | 2.48% | 16.29% | 18.98% | 0.0563% |
| Lam Research Corp | LRCX | 40,610.93 | 0.16% | 1.68% | 12.09% | 13.87% | 0.0228% |
| Southwest Airlines Co | LUV | 15,868.50 | 0.06% | 1.62% | 4.03% | 5.68% | 0.0036% |
| Las Vegas Sands Corp | LVS | 35,902.93 | 0.15% | 5.76% | 6.10% | 12.04% | 0.0175% |
| Lamb Weston Holdings Inc | LW | 8,750.65 | 0.04% | 1.43% | -1.85% | -0.43% | -0.0002% |
| LyondellBasell Industries NV | LYB | 17,411.52 | 0.07% | 8.25% | 6.20% | 14.71% | 0.0104% |
| Live Nation Entertainment Inc | LYV | 8,227.27 | N/A | 0.00% | N/A | N/A | N/A |
| Mastercard Inc | MA | 261,298.18 | 1.06% | 0.55% | 16.43% | 17.03% | 0.1800% |
| Mid-America Apartment Communities Inc | MAA | 12,970.74 | N/A | 3.53% | N/A | N/A | N/A |
| Marriott International Inc/MD | MAR | 27,318.88 | 0.11% | 0.57% | 0.42% | 0.99% | 0.0011% |
| Masco Corp | MAS | 10,547.58 | 0.04% | 1.36% | 10.18% | 11.61% | 0.0050% |
| McDonald's Corp | MCD | 138,368.16 | 0.56% | 2.68% | 7.15% | 9.93% | 0.0556% |
| Microchip Technology Inc | MCHP | 19,244.49 | 0.08% | 1.69% | 8.31% | 10.07% | 0.0078% |
| McKesson Corp | MCK | 22,870.57 | 0.09% | 1.17% | 3.90% | 5.08% | 0.0047% |
| Moody's Corp | MCO | 44,810.04 | 0.18% | 0.94% | 11.70% | 12.69% | 0.0230% |
| Mondelez International Inc | MDLZ | 76,460.05 | 0.31% | 2.18% | 7.80% | 10.07% | 0.0311% |
| Medtronic PLC | MDT | 138,479.37 | 0.56% | 2.07% | 7.38% | 9.52% | 0.0534% |
| MetLife Inc | MET | 30,277.28 | 0.12% | 5.59% | 4.58% | 10.30% | 0.0126% |
| MGM Resorts International | MGM | 6,937.09 | 0.03% | 3.81% | 16.23% | 20.35% | 0.0057% |
| Mohawk Industries Inc | MHK | 5,666.28 | 0.02% | 0.00% | 1.57% | 1.57% | 0.0004% |
| McCormick & Co Inc/MD | MKC | 20,835.66 | 0.08% | 1.54% | 9.17% | 10.78% | 0.0091% |
| MarketAxess Holdings Inc | MKTX | 16,297.93 | N/A | 0.55% | N/A | N/A | N/A |
| Martin Marietta Materials Inc | MLM | 12,358.52 | 0.05% | 1.06% | 13.48% | 14.61% | 0.0073% |
| Marsh & McLennan Cos Inc | MMC | 49,673.63 | 0.20% | 1.93% | 11.12% | 13.16% | 0.0264% |
| 3M Co | MMM | 84,252.68 | 0.34% | 4.03% | 7.05% | 11.22% | 0.0382% |
| Monster Beverage Corp | MNST | 33,389.57 | 0.14% | 0.00% | 7.90% | 7.90% | 0.0107% |
| Altria Group Inc | MO | 75,914.34 | 0.31% | 8.32% | 5.25% | 13.79% | 0.0424% |
| Mosaic Co/The | MOS | 4,339.78 | 0.02% | 1.76% | 7.00% | 8.83% | 0.0015% |
| Marathon Petroleum Corp | MPC | 16,542.52 | 0.07% | 9.17% | 15.18% | 25.04% | 0.0168% |
| Merck & Co Inc | MRK | 210,743.74 | 0.85% | 2.88% | 7.72% | 10.71% | 0.0913% |
| Marathon Oil Corp | MRO | 3,438.32 | 0.01% | 4.60% | -3.20% | 1.32% | 0.0002% |
| Morgan Stanley | MS | 61,605.84 | 0.25% | 3.66% | -0.03% | 3.63% | 0.0091% |
| MSCI Inc | MSCI | 26,964.98 | 0.11% | 0.89% | 13.17% | 14.11% | 0.0154% |
| Microsoft Corp | MSFT | 1,358,440.00 | 5.50% | 1.11% | 12.86% | 14.04% | 0.7716% |
| Motorola Solutions Inc | MSI | 27,065.95 | 0.11% | 1.61% | 8.90% | 10.58% | 0.0116% |
| M&T Bank Corp | MTB | 13,707.19 | 0.06% | 4.21% | -0.73% | 3.46% | 0.0019% |
| Mettler-Toledo International Inc | MTD | 17,287.80 | 0.07% | 0.00% | 12.16% | 12.16% | 0.0085% |
| Micron Technology Inc | MU | 50,826.90 | 0.21% | 0.00% | 6.95% | 6.95% | 0.0143% |
| Maxim Integrated Products Inc | MXIM | 14,302.14 | 0.06% | 3.62% | 10.00% | 13.80% | 0.0080% |
| Mylan NV | MYL | 8,315.61 | 0.03% | 0.70% | 0.43% | 1.14% | 0.0004% |
| Noble Energy Inc | NBL | 3,371.03 | 0.01% | 4.99% | 5.87% | 11.00% | 0.0015% |
| Norwegian Cruise Line Holdings Ltd | NCLH | 2,639.45 | 0.01% | 0.21% | -56.12% | -55.97% | -0.0060% |
| Nasdaq Inc | NDAQ | 18,282.05 | 0.07% | 1.78% | 12.01% | 13.90% | 0.0103% |
| NextEra Energy Inc | NEE | 120,527.74 | 0.49% | 2.28% | 8.32% | 10.70% | 0.0522% |
| Newmont Corp | NEM | 47,845.25 | 0.19% | 1.64% | -3.00% | -1.39% | -0.0027% |
| Netflix Inc | NFLX | 185,597.66 | 0.75% | 0.00% | 26.38% | 26.38% | 0.1981% |
| NiSource Inc | NI | 10,095.19 | 0.04% | 3.21% | 4.68% | 7.97% | 0.0033% |
| NIKE Inc | NKE | 139,813.17 | 0.57% | 1.04% | 12.09% | 13.19% | 0.0746% |
| NortonLifeLock Inc | NLOK | 12,079.73 | 0.05% | 41.53% | 2.05% | 44.01% | 0.0215% |
| Nielsen Holdings PLC | NLSN | 4,726.86 | 0.02% | 1.81% | 8.75% | 10.64% | 0.0020% |
| Northrop Grumman Corp | NOC | 59,606.57 | 0.24% | 1.57% | 20.99% | 22.73% | 0.0548% |
| National Oilwell Varco Inc | NOV | 4,530.56 | N/A | 1.69% | N/A | N/A | N/A |
| ServiceNow Inc | NOW | 56,862.18 | 0.23% | 0.00% | 30.15% | 30.15% | 0.0694% |
| NRG Energy Inc | NRG | 7,859.50 | 0.03% | 3.83% | -11.51% | -7.90% | -0.0025% |
| Norfolk Southern Corp | NSC | 41,308.99 | 0.17% | 2.36% | 6.95% | 9.40% | 0.0157% |
| NetApp Inc | NTAP | 9,322.61 | 0.04% | 4.54% | 5.20% | 9.86% | 0.0037% |
| Northern Trust Corp | NTRS | 16,741.35 | 0.07% | 3.57% | -2.87% | 0.65% | 0.0004% |
| Nucor Corp | NUE | 11,236.45 | 0.05% | 4.31% | 12.00% | 16.57% | 0.0075% |
| NVIDIA Corp | NVDA | 179,041.78 | 0.72% | 0.23% | 14.44% | 14.68% | 0.1063% |
| NVR Inc | NVR | 10,760.76 | 0.04% | 0.00% | 8.89% | 8.89% | 0.0039% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Newell Brands Inc | NWL | 5,760.95 | 0.02% | 6.69% | -2.82% | 3.77% | 0.0009% |
| News Corp | NWSA | 5,289.47 | 0.02% | 2.11% | -9.39% | -7.38% | -0.0016% |
| Realty Income Corp | O | 17,983.75 | 0.07% | 5.34% | 3.73% | 9.17% | 0.0067% |
| Old Dominion Freight Line Inc | ODFL | 16,335.95 | 0.07% | 0.51% | 8.99% | 9.52% | 0.0063% |
| ONEOK Inc | OKE | 12,159.12 | 0.05% | 12.81% | 9.15% | 22.55% | 0.0111% |
| Omnicom Group Inc | OMC | 11,834.47 | 0.05% | 4.86% | 4.13% | 9.09% | 0.0044% |
| Oracle Corp | ORCL | 172,248.76 | 0.70% | 1.75% | 9.25% | 11.08% | 0.0772% |
| O'Reilly Automotive Inc | ORLY | 27,733.70 | 0.11% | 0.00% | 9.19% | 9.19% | 0.0103% |
| Otis Worldwide Corp | OTIS | 19,986.62 | N/A | 0.00% | N/A | N/A | N/A |
| Occidental Petroleum Corp | OXY | 12,267.25 | 0.05% | 11.94% | -1.50% | 10.35% | 0.0051% |
| Paycom Software Inc | PAYC | 13,236.54 | 0.05% | 0.00% | 22.35% | 22.35% | 0.0120% |
| Paychex Inc | PAYX | 24,213.29 | 0.10% | 3.69% | 7.00% | 10.82% | 0.0106% |
| People's United Financial Inc | PBCT | 4,875.11 | 0.02% | 6.23% | 2.00% | 8.29% | 0.0016% |
| PACCAR Inc | PCAR | 23,433.43 | 0.09% | 4.14% | 0.70% | 4.85% | 0.0046% |
| Healthpeak Properties Inc | PEAK | 13,277.88 | 0.05% | 5.65% | 3.04% | 8.77% | 0.0047% |
| Public Service Enterprise Group Inc | PEG | 27,590.05 | 0.11% | 3.59% | 4.52% | 8.19% | 0.0091% |
| PepsiCo Inc | PEP | 191,090.10 | 0.77% | 2.92% | 4.16% | 7.14% | 0.0552% |
| Pfizer Inc | PFE | 204,763.36 | 0.83% | 4.08% | 3.10% | 7.25% | 0.0600% |
| Principal Financial Group Inc | PFG | 8,347.92 | 0.03% | 7.44% | 1.95% | 9.46% | 0.0032% |
| Procter & Gamble Co/The | PG | 307,916.08 | 1.25% | 2.39% | 7.20% | 9.68% | 0.1206% |
| Progressive Corp/The | PGR | 48,287.25 | 0.20% | 3.27% | 6.00% | 9.37% | 0.0183% |
| Parker-Hannifin Corp | PH | 17,791.13 | 0.07% | 2.56% | 9.19% | 11.86% | 0.0085% |
| PulteGroup Inc | PHM | 6,877.13 | 0.03% | 1.87% | 10.77% | 12.74% | 0.0035% |
| Packaging Corp of America | PKG | 8,616.17 | 0.03% | 3.48% | -4.10% | -0.69% | -0.0002% |
| PerkinElmer Inc | PKI | 9,308.39 | 0.04% | 0.33% | 5.14% | 5.49% | 0.0021% |
| Prologis Inc | PLD | 66,680.66 | 0.27% | 2.52% | 6.72% | 9.32% | 0.0252% |
| Philip Morris International Inc | PM | 121,391.95 | 0.49% | 6.11% | 6.45% | 12.75% | 0.0626% |
| PNC Financial Services Group Inc/The | PNC | 43,036.00 | 0.17% | 4.55% | -3.03% | 1.46% | 0.0025% |
| Pentair PLC | PNR | 5,307.32 | 0.02% | 2.37% | 4.33% | 6.75% | 0.0015% |
| Pinnacle West Capital Corp | PNW | 8,988.98 | 0.04% | 3.96% | 4.59% | 8.64% | 0.0031% |
| PPG Industries Inc | PPG | 22,012.81 | 0.09% | 2.25% | 4.54% | 6.83% | 0.0061% |
| PPL Corp | PPL | 20,272.26 | 0.08% | 6.29% | 0.70% | 7.01% | 0.0057% |
| Perrigo Co PLC | PRGO | 7,060.89 | 0.03% | 1.75% | -1.00% | 0.75% | 0.0002% |
| Prudential Financial Inc | PRU | 22,416.09 | 0.09% | 7.77% | 7.83% | 15.91% | 0.0144% |
| Public Storage | PSA | 34,312.67 | 0.14% | 4.14% | 4.09% | 8.32% | 0.0115% |
| Phillips 66 | PSX | 26,064.48 | 0.11% | 6.21% | 7.02% | 13.45% | 0.0142% |
| PVH Corp | PVH | 3,181.25 | 0.01% | 0.16% | 2.97% | 3.13% | 0.0004% |
| Quanta Services Inc | PWR | 4,822.19 | 0.02% | 0.55% | 10.00% | 10.58% | 0.0021% |
| Pioneer Natural Resources Co | PXD | 12,633.46 | 0.05% | 2.83% | 18.98% | 22.08% | 0.0113% |
| PayPal Holdings Inc | PYPL | 131,187.87 | 0.53% | 0.00% | 22.44% | 22.44% | 0.1191% |
| QUALCOMM Inc | QCOM | 87,065.57 | 0.35% | 3.33% | 16.31% | 19.91% | 0.0701% |
| Qorvo Inc | QRVO | 9,980.11 | 0.04% | 0.05% | 11.15% | 11.20% | 0.0045% |
| Royal Caribbean Cruises Ltd | RCL | 7,814.51 | 0.03% | 6.65% | -29.88% | -24.22% | -0.0077% |
| Everest Re Group Ltd | RE | 8,941.96 | 0.04% | 2.72% | 10.00% | 12.86% | 0.0047% |
| Regency Centers Corp | REG | 6,490.31 | 0.03% | 5.69% | 5.68% | 11.53% | 0.0030% |
| Regeneron Pharmaceuticals Inc | REGN | 62,578.17 | 0.25% | 0.00% | 8.74% | 8.74% | 0.0221% |
| Regions Financial Corp | RF | 9,114.38 | 0.04% | 6.68% | -3.62% | 2.94% | 0.0011% |
| Robert Half International Inc | RHI | 4,961.41 | 0.02% | 3.04% | -1.18% | 1.85% | 0.0004% |
| Raymond James Financial Inc | RJF | 8,868.21 | 0.04% | 2.26% | 9.50% | 11.87% | 0.0043% |
| Ralph Lauren Corp | RL | 5,359.65 | 0.02% | 3.75% | 2.62% | 6.41% | 0.0014% |
| ResMed Inc | RMD | 23,884.93 | 0.10% | 1.04% | 15.88% | 17.00% | 0.0164% |
| Rockwell Automation Inc | ROK | 19,587.40 | 0.08% | 2.41% | 5.75% | 8.23% | 0.0065% |
| Rollins Inc | ROL | 12,770.19 | N/A | 1.36% | N/A | N/A | N/A |
| Roper Technologies Inc | ROP | 34,164.13 | 0.14% | 0.63% | 11.93% | 12.60% | 0.0174% |
| Ross Stores Inc | ROST | 32,596.10 | 0.13% | 1.18% | 8.67% | 9.90% | 0.0131% |
| Republic Services Inc | RSG | 25,621.64 | 0.10% | 2.06% | 5.05% | 7.16% | 0.0074% |
| Raytheon Technologies Corp | RTX | 100,179.89 | 0.41% | 3.25% | -3.56% | -0.36% | -0.0015% |
| SBA Communications Corp | SBAC | 35,324.27 | 0.14% | 0.60% | 10.00% | 10.63% | 0.0152% |
| Starbucks Corp | SBUX | 90,492.27 | 0.37% | 2.16% | 13.60% | 15.91% | 0.0582% |
| Charles Schwab Corp/The | SCHW | 46,071.60 | 0.19% | 2.02% | 5.00% | 7.07% | 0.0132% |
| Sealed Air Corp | SEE | 4,591.90 | 0.02% | 2.15% | 4.67% | 6.87% | 0.0013% |
| Sherwin-Williams Co/The | SHW | 47,439.70 | 0.19% | 0.99% | 11.71% | 12.75% | 0.0245% |
| SVB Financial Group | SIVB | 8,953.17 | 0.04% | 0.00% | 8.00% | 8.00% | 0.0029% |
| JM Smucker Co/The | SJM | 13,864.73 | 0.06% | 2.83% | 0.49% | 3.33% | 0.0019% |
| Schlumberger Ltd | SLB | 21,211.12 | 0.09% | 10.29% | 50.00% | 62.87% | 0.0540% |
| SL Green Realty Corp | SLG | 4,047.53 | 0.02% | 6.69% | 4.98% | 11.84% | 0.0019% |
| Snap-on Inc | SNA | 6,471.17 | 0.03% | 3.58% | 5.06% | 8.73% | 0.0023% |
| Synopsys Inc | SNPS | 23,282.20 | 0.09% | 0.00% | 14.14% | 14.14% | 0.0133% |
| Southern Co/The | SO | 60,746.17 | 0.25% | 4.42% | 4.18% | 8.70% | 0.0214% |
| Simon Property Group Inc | SPG | 17,151.52 | 0.07% | 14.47% | 1.83% | 16.44% | 0.0114% |
| S&P Global Inc | SPGI | 68,087.05 | 0.28% | 0.90% | 11.80% | 12.76% | 0.0351% |
| Sempra Energy | SRE | 36,385.33 | 0.15% | 3.36% | 7.22% | 10.71% | 0.0158% |
| STERIS PLC | STE | 13,143.49 | 0.05% | 0.93% | 10.10% | 11.08% | 0.0059% |
| State Street Corp | STT | 20,600.21 | 0.08% | 3.60% | 1.83% | 5.46% | 0.0045% |
| Seagate Technology PLC | STX | 13,431.41 | 0.05% | 4.99% | 8.11% | 13.30% | 0.0072% |
| Constellation Brands Inc | STZ | 31,291.39 | 0.13% | 1.87% | 2.11% | 4.00% | 0.0051% |
| Stanley Black & Decker Inc | SWK | 17,334.03 | 0.07% | 2.48% | 4.87% | 7.41% | 0.0052% |
| Skyworks Solutions Inc | SWKS | 16,176.29 | 0.07% | 1.85% | 11.84% | 13.80% | 0.0090% |
| Synchrony Financial | SYF | 9,110.09 | 0.04% | 5.73% | -7.98% | -2.48% | -0.0009% |
| Stryker Corp | SYK | 71,033.69 | 0.29% | 1.22% | 8.90% | 10.17% | 0.0292% |
| Sysco Corp | SYY | 25,583.07 | 0.10% | 3.46% | 8.97% | 12.58% | 0.0130% |
| AT&T Inc | T | 224,328.39 | 0.91% | 6.68% | 4.62% | 11.45% | 0.1040% |
| Molson Coors Beverage Co | TAP | 9,739.03 | 0.04% | 4.95% | -6.37% | -1.58% | -0.0006% |
| TransDigm Group Inc | TDG | 18,114.22 | 0.07% | 3.85% | 7.17% | 11.16% | 0.0082% |
| TE Connectivity Ltd | TEL | 22,534.54 | 0.09% | 2.73% | 7.18% | 10.01% | 0.0091% |
| Truist Financial Corp | TFC | 44,923.05 | 0.18% | 5.49% | -2.44% | 2.98% | 0.0054% |
| Teleflex Inc | TFX | 16,075.80 | 0.07% | 0.39% | 13.53% | 13.95% | 0.0091% |
| Target Corp | TGT | 56,819.10 | 0.23% | 2.46% | 9.41% | 11.98% | 0.0275% |
| Tiffany & Co | TIF | 15,651.86 | N/A | 1.90% | N/A | N/A | N/A |
| TJX Cos Inc/The | TJX | 59,561.53 | 0.24% | 1.49% | 8.40% | 9.95% | 0.0240% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Thermo Fisher Scientific Inc | TMO | 130,957.89 | 0.53% | 0.25% | 10.60% | 10.87% | 0.0576% |
| T-Mobile US Inc | TMUS | 111,852.65 | 0.45% | 0.66% | 6.00% | 6.68% | 0.0302% |
| Tapestry Inc | TPR | 4,201.16 | 0.02% | 7.98% | 9.30% | 17.65% | 0.0030% |
| T Rowe Price Group Inc | TROW | 24,150.92 | 0.10% | 3.46% | -2.96% | 0.46% | 0.0004% |
| Travelers Cos Inc/The | TRV | 26,569.81 | 0.11% | 3.25% | 10.00% | 13.41% | 0.0144% |
| Tractor Supply Co | TSCO | 10,757.81 | 0.04% | 1.57% | 10.45% | 12.10% | 0.0053% |
| Tyson Foods Inc | TSN | 22,756.48 | 0.09% | 2.73% | 5.44% | 8.24% | 0.0076% |
| Trane Technologies PLC | TT | 21,434.64 | 0.09% | 2.33% | 2.51% | 4.86% | 0.0042% |
| Take-Two Interactive Software Inc | TTWO | 14,114.52 | 0.06% | 0.00% | 8.70% | 8.70% | 0.0050% |
| Twitter Inc | TWTR | 20,949.60 | 0.08% | 0.00% | 39.40% | 39.40% | 0.0334% |
| Texas Instruments Inc | TXN | 106,019.99 | 0.43% | 3.20% | 7.50% | 10.82% | 0.0464% |
| Textron Inc | TXT | 6,317.16 | N/A | 0.29% | N/A | N/A | N/A |
| Under Armour Inc | UAA | 4,214.98 | 0.02% | 0.00% | 12.77% | 12.77% | 0.0022% |
| United Airlines Holdings Inc | UAL | 7,190.23 | 0.03% | 0.00% | 1.56% | 1.56% | 0.0005% |
| UDR Inc | UDR | 11,482.67 | N/A | 3.69% | N/A | N/A | N/A |
| Universal Health Services Inc | UHS | 9,227.72 | 0.04% | 0.74% | 8.59% | 9.36% | 0.0035% |
| Ulta Beauty Inc | ULTA | 12,135.26 | 0.05% | 0.00% | 15.68% | 15.68% | 0.0077% |
| UnitedHealth Group Inc | UNH | 275,617.48 | 1.12% | 1.58% | 11.80% | 13.47% | 0.1502% |
| Unum Group | UNM | 3,153.57 | 0.01% | 7.59% | 9.00% | 16.93% | 0.0022% |
| Union Pacific Corp | UNP | 101,708.45 | 0.41% | 2.60% | 7.50% | 10.20% | 0.0420% |
| United Parcel Service Inc | UPS | 88,205.40 | 0.36% | 3.90% | 8.45% | 12.51% | 0.0447% |
| United Rentals Inc | URI | 7,781.89 | 0.03% | 0.00% | -15.30% | -15.30% | -0.0048% |
| US Bancorp | USB | 52,800.36 | 0.21% | 4.80% | 6.43% | 11.38% | 0.0243% |
| Visa Inc | V | 332,723.43 | 1.35% | 0.69% | 14.60% | 15.34% | 0.2066% |
| Varian Medical Systems Inc | VAR | 10,494.57 | 0.04% | 0.00% | 8.40% | 8.40% | 0.0036% |
| VF Corp | VFC | 22,696.42 | 0.09% | 3.29% | 6.88% | 10.28% | 0.0094% |
| ViacomCBS Inc | VIAC | 9,838.01 | 0.04% | 5.81% | 1.85% | 7.71% | 0.0031% |
| Valero Energy Corp | VLO | 21,146.33 | 0.09% | 7.63% | 8.06% | 16.00% | 0.0137% |
| Vulcan Materials Co | VMC | 14,850.17 | 0.06% | 1.07% | 15.30% | 16.46% | 0.0099% |
| Vornado Realty Trust | VNO | 8,035.92 | 0.03% | 8.02% | 3.80% | 11.97% | 0.0039% |
| Verisk Analytics Inc | VRSK | 24,983.47 | 0.10% | 0.70% | 10.00% | 10.74% | 0.0109% |
| VeriSign Inc | VRSN | 24,301.69 | 0.10% | 0.00% | 4.00% | 4.00% | 0.0039% |
| Vertex Pharmaceuticals Inc | VRTX | 70,121.78 | 0.28% | 0.00% | 41.58% | 41.58% | 0.1180% |
| Ventas Inc | VTR | 11,673.17 | 0.05% | 9.63% | -2.32% | 7.20% | 0.0034% |
| Verizon Communications Inc | VZ | 241,782.60 | 0.98% | 4.25% | 2.96% | 7.27% | 0.0711% |
| Westinghouse Air Brake Technologies Corp | WAB | 9,358.60 | 0.04% | 1.01% | 15.00% | 16.09% | 0.0061% |
| Waters Corp | WAT | 12,244.36 | 0.05% | 0.00% | 3.98% | 3.98% | 0.0020% |
| Walgreens Boots Alliance Inc | WBA | 39,036.30 | 0.16% | 4.17% | 9.09% | 13.45% | 0.0212% |
| Western Digital Corp | WDC | 12,650.78 | 0.05% | 4.73% | 3.52% | 8.33% | 0.0043% |
| WEC Energy Group Inc | WEC | 31,650.70 | 0.13% | 2.50% | 6.60% | 9.18% | 0.0118% |
| Welltower Inc | WELL | 20,158.28 | 0.08% | 6.94% | 0.50% | 7.45% | 0.0061% |
| Wells Fargo & Co | WFC | 116,255.83 | 0.47% | 7.21% | 9.41% | 16.95% | 0.0797% |
| Whirlpool Corp | WHR | 6,601.85 | 0.03% | 4.77% | 0.17% | 4.94% | 0.0013% |
| Willis Towers Watson PLC | WLTW | 25,150.75 | 0.10% | 1.44% | 10.00% | 11.51% | 0.0117% |
| Waste Management Inc | WM | 42,477.10 | N/A | 2.18% | N/A | N/A | N/A |
| Williams Cos Inc/The | WMB | 21,933.27 | 0.09% | 8.81% | 3.50% | 12.47% | 0.0111% |
| Walmart Inc | WMT | 374,200.47 | 1.51% | 1.65% | 5.30% | 6.99% | 0.1058% |
| WR Berkley Corp | WRB | 10,453.20 | N/A | 2.40% | N/A | N/A | N/A |
| Westrock Co | WRK | 7,932.02 | 0.03% | 6.04% | -10.90% | -5.19% | -0.0017% |
| Western Union Co/The | WU | 8,188.67 | 0.03% | 4.40% | 5.33% | 9.85% | 0.0033% |
| Weyerhaeuser Co | WY | 14,998.74 | N/A | 6.77% | N/A | N/A | N/A |
| Wynn Resorts Ltd | WYNN | 8,435.72 | 0.03% | 3.43% | 21.50% | 25.30% | 0.0086% |
| Xcel Energy Inc | XEL | 35,255.73 | 0.14% | 2.56% | 5.92% | 8.56% | 0.0122% |
| Xilinx Inc | XLNX | 22,146.45 | 0.09% | 1.66% | 6.87% | 8.58% | 0.0077% |
| Exxon Mobil Corp | XOM | 182,839.20 | 0.74% | 7.83% | 1.73% | 9.62% | 0.0711% |
| DENTSPLY SIRONA Inc | XRAY | 8,949.41 | 0.04% | 0.93% | 3.27% | 4.22% | 0.0015% |
| Xerox Holdings Corp | XRX | 3,856.51 | N/A | 5.53% | N/A | N/A | N/A |
| Xylem Inc/NY | XYL | 12,520.35 | 0.05% | 1.47% | 11.65% | 13.21% | 0.0067% |
| Yum! Brands Inc | YUM | 25,326.75 | 0.10% | 2.14% | 12.00% | 14.27% | 0.0146% |
| Zimmer Biomet Holdings Inc | ZBH | 24,508.30 | 0.10% | 0.86% | 4.89% | 5.78% | 0.0057% |
| Zebra Technologies Corp | ZBRA | 10,771.13 | 0.04% | 0.00% | 11.05% | 11.05% | 0.0048% |
| Zions Bancorp NA | ZION | 4,769.50 | 0.02% | 4.80% | -5.41% | -0.74% | -0.0001% |
| Zoetis Inc | ZTS | 62,080.30 | N/A | 0.61% | N/A | N/A | N/A |
| | Total Market Capitalization: | 24,715,828 | | | | | 12.93% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 14.82% | 1.37% | 13.45% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 23,773.90 | 0.11% | 0.94% | 10.50% | 11.49% | 0.0123% |
| American Airlines Group Inc | AAL | 4,851.54 | 0.02% | 3.53% | 6.50% | 10.14% | 0.0022% |
| Advance Auto Parts Inc | AAP | 7,097.67 | 0.03% | 0.98% | 14.00% | 15.05% | 0.0048% |
| Apple Inc | AAPL | 1,166,706.00 | 5.23% | 1.23% | 14.00% | 15.32% | 0.8014% |
| AbbVie Inc | ABBV | 116,183.20 | 0.52% | 6.01% | 8.00% | 14.25% | 0.0743% |
| AmerisourceBergen Corp | ABC | 18,176.37 | 0.08% | 1.90% | 7.50% | 9.47% | 0.0077% |
| ABIOMED Inc | ABMD | 7,049.81 | 0.03% | 0.00% | 11.00% | 11.00% | 0.0035% |
| Abbott Laboratories | ABT | 150,230.30 | 0.67% | 1.70% | 10.50% | 12.29% | 0.0828% |
| Accenture PLC | ACN | 109,532.70 | 0.49% | 1.91% | 8.50% | 10.49% | 0.0515% |
| Adobe Inc | ADBE | 153,197.90 | 0.69% | 0.00% | 20.50% | 20.50% | 0.1408% |
| Analog Devices Inc | ADI | 37,337.51 | 0.17% | 2.45% | 7.00% | 9.54% | 0.0160% |
| Archer-Daniels-Midland Co | ADM | 20,319.36 | 0.09% | 3.95% | 9.00% | 13.13% | 0.0120% |
| Automatic Data Processing Inc | ADP | 59,817.25 | 0.27% | 2.79% | 13.50% | 16.48% | 0.0442% |
| Alliance Data Systems Corp | ADS | 1,937.80 | 0.01% | 6.19% | 8.00% | 14.44% | 0.0013% |
| Autodesk Inc | ADSK | 35,031.45 | N/A | 0.00% | N/A | N/A | N/A |
| Ameren Corp | AEE | 18,713.66 | 0.08% | 2.67% | 6.00% | 8.75% | 0.0073% |
| American Electric Power Co Inc | AEP | 41,164.28 | 0.18% | 3.46% | 5.00% | 8.55% | 0.0158% |
| AES Corp/VA | AES | 9,380.81 | N/A | 4.03% | N/A | N/A | N/A |
| Aflac Inc | AFL | 27,450.97 | 0.12% | 2.99% | 7.00% | 10.09% | 0.0124% |
| Allergan PLC | AGN | 59,412.34 | 0.27% | 1.64% | 2.50% | 4.16% | 0.0111% |
| American International Group Inc | AIG | 20,993.08 | N/A | 5.31% | N/A | N/A | N/A |
| Apartment Investment & Management Co | AIV | 5,575.97 | 0.03% | 4.49% | -1.50% | 2.96% | 0.0007% |
| Assurant Inc | AIZ | 6,484.20 | 0.03% | 2.36% | 8.00% | 10.45% | 0.0030% |
| Arthur J Gallagher & Co | AJG | 15,859.96 | 0.07% | 2.12% | 14.50% | 16.77% | 0.0119% |
| Akamai Technologies Inc | AKAM | 15,774.04 | 0.07% | 0.00% | 14.00% | 14.00% | 0.0099% |
| Albemarle Corp | ALB | 6,555.39 | 0.03% | 2.49% | 5.50% | 8.06% | 0.0024% |
| Align Technology Inc | ALGN | 14,533.17 | 0.07% | 0.00% | 20.00% | 20.00% | 0.0130% |
| Alaska Air Group Inc | ALK | 3,584.22 | 0.02% | 5.15% | 6.50% | 11.82% | 0.0019% |
| Allstate Corp/The | ALL | 31,022.75 | 0.14% | 2.22% | 9.00% | 11.32% | 0.0157% |
| Allegion plc | ALLE | 8,776.33 | 0.04% | 1.35% | 9.00% | 10.41% | 0.0041% |
| Alexion Pharmaceuticals Inc | ALXN | 21,811.33 | 0.10% | 0.00% | 37.50% | 37.50% | 0.0367% |
| Applied Materials Inc | AMAT | 47,255.97 | 0.21% | 1.71% | 7.50% | 9.27% | 0.0197% |
| Amcor PLC | AMCR | 13,777.69 | N/A | 5.64% | N/A | N/A | N/A |
| Advanced Micro Devices Inc | AMD | 57,084.30 | 0.26% | 0.00% | 18.00% | 18.00% | 0.0461% |
| AMETEK Inc | AME | 17,692.08 | 0.08% | 0.93% | 12.50% | 13.49% | 0.0107% |
| Amgen Inc | AMGN | 129,629.00 | 0.58% | 2.99% | 6.50% | 9.59% | 0.0557% |
| Ameriprise Financial Inc | AMP | 14,229.87 | 0.06% | 3.47% | 12.50% | 16.19% | 0.0103% |
| American Tower Corp | AMT | 110,376.60 | 0.50% | 1.84% | 11.50% | 13.45% | 0.0666% |
| Amazon.com Inc | AMZN | 1,011,285.00 | 4.54% | 0.00% | 39.00% | 39.00% | 1.7688% |
| Arista Networks Inc | ANET | 16,392.31 | 0.07% | 0.00% | 5.50% | 5.50% | 0.0040% |
| ANSYS Inc | ANSS | 20,950.82 | 0.09% | 0.00% | 13.00% | 13.00% | 0.0122% |
| Anthem Inc | ANTM | 62,476.79 | 0.28% | 1.54% | 14.00% | 15.65% | 0.0438% |
| Aon PLC | AON | 44,001.43 | 0.20% | 0.94% | 11.00% | 11.99% | 0.0237% |
| AO Smith Corp | AOS | 6,530.56 | 0.03% | 2.39% | 6.00% | 8.46% | 0.0025% |
| Apache Corp | APA | 2,850.25 | 0.01% | 1.32% | 46.00% | 47.62% | 0.0061% |
| Air Products & Chemicals Inc | APD | 47,613.49 | 0.21% | 2.48% | 10.50% | 13.11% | 0.0280% |
| Amphenol Corp | APH | 23,663.06 | 0.11% | 1.26% | 9.00% | 10.32% | 0.0109% |
| Aptiv PLC | APTV | 15,368.34 | 0.07% | 0.00% | 9.50% | 9.50% | 0.0065% |
| Alexandria Real Estate Equities Inc | ARE | 16,367.61 | 0.07% | 2.79% | 16.50% | 19.52% | 0.0143% |
| Atmos Energy Corp | ATO | 12,550.19 | 0.06% | 2.32% | 7.00% | 9.40% | 0.0053% |
| Activision Blizzard Inc | ATVI | 46,948.17 | 0.21% | 0.67% | 8.00% | 8.70% | 0.0183% |
| AvalonBay Communities Inc | AVB | 22,262.39 | 0.10% | 4.01% | 2.50% | 6.56% | 0.0065% |
| Broadcom Inc | AVGO | 104,178.90 | 0.47% | 4.98% | 17.00% | 22.40% | 0.1047% |
| Avery Dennison Corp | AVY | 9,211.90 | 0.04% | 2.25% | 9.50% | 11.86% | 0.0049% |
| American Water Works Co Inc | AWK | 22,664.91 | 0.10% | 1.69% | 8.50% | 10.26% | 0.0104% |
| American Express Co | AXP | 74,584.80 | 0.33% | 1.93% | 10.00% | 12.03% | 0.0402% |
| AutoZone Inc | AZO | 21,496.69 | 0.10% | 0.00% | 13.50% | 13.50% | 0.0130% |
| Boeing Co/The | BA | 82,674.45 | 0.37% | 0.00% | 16.00% | 16.00% | 0.0593% |
| Bank of America Corp | BAC | 207,207.70 | 0.93% | 3.24% | 10.50% | 13.91% | 0.1293% |
| Baxter International Inc | BAX | 42,918.63 | 0.19% | 1.04% | 10.50% | 11.59% | 0.0223% |
| Best Buy Co Inc | BBY | 16,757.00 | 0.08% | 3.41% | 10.50% | 14.09% | 0.0106% |
| Becton Dickinson and Co | BDX | 67,793.25 | 0.30% | 1.27% | 9.00% | 10.33% | 0.0314% |
| Franklin Resources Inc | BEN | 8,553.74 | 0.04% | 6.40% | 10.00% | 16.72% | 0.0064% |
| Brown-Forman Corp | BF/B | 29,212.47 | 0.13% | 1.14% | 11.00% | 12.20% | 0.0160% |
| Biogen Inc | BIIB | 57,653.21 | 0.26% | 0.00% | 9.50% | 9.50% | 0.0246% |
| Bank of New York Mellon Corp/The | BK | 32,109.35 | 0.14% | 3.48% | 7.00% | 10.60% | 0.0153% |
| Booking Holdings Inc | BKNG | 57,743.15 | 0.26% | 0.00% | 12.00% | 12.00% | 0.0311% |
| Baker Hughes Co | BKR | 8,385.00 | N/A | 5.58% | N/A | N/A | N/A |
| BlackRock Inc | BLK | 69,618.94 | 0.31% | 3.22% | 10.00% | 13.38% | 0.0418% |
| Ball Corp | BLL | 21,942.08 | 0.10% | 0.89% | 21.00% | 21.98% | 0.0216% |
| Bristol-Myers Squibb Co | BMY | 94,905.85 | 0.43% | 3.09% | 9.50% | 12.74% | 0.0542% |
| Broadridge Financial Solutions Inc | BR | 11,721.08 | 0.05% | 2.29% | 11.00% | 13.42% | 0.0071% |
| Berkshire Hathaway Inc | BRK/B | - | N/A | 0.00% | N/A | N/A | N/A |
| Boston Scientific Corp | BSX | 48,963.35 | 0.22% | 0.00% | 14.00% | 14.00% | 0.0307% |
| BorgWarner Inc | BWA | 5,269.60 | 0.02% | 2.66% | 6.00% | 8.74% | 0.0021% |
| Boston Properties Inc | BXP | 15,431.90 | 0.07% | 3.98% | 3.50% | 7.55% | 0.0052% |
| Citigroup Inc | C | 96,628.17 | 0.43% | 4.88% | 10.00% | 15.12% | 0.0655% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Conagra Brands Inc | CAG | 15,250.35 | 0.07% | 2.78% | 5.00% | 7.85% | 0.0054% |
| Cardinal Health Inc | CAH | 14,424.80 | 0.06% | 3.91% | 11.00% | 15.13% | 0.0098% |
| Carrier Global Corp | CARR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Caterpillar Inc | CAT | 70,408.63 | 0.32% | 3.23% | 10.50% | 13.90% | 0.0439% |
| Chubb Ltd | CB | 51,979.53 | 0.23% | 2.62% | 9.00% | 11.74% | 0.0274% |
| Cboe Global Markets Inc | CBOE | 10,589.78 | 0.05% | 1.51% | 12.50% | 14.10% | 0.0067% |
| CBRE Group Inc | CBRE | 15,196.27 | 0.07% | 0.00% | 10.50% | 10.50% | 0.0072% |
| Crown Castle International Corp | CCI | 65,461.75 | 0.29% | 3.15% | 15.50% | 18.89% | 0.0555% |
| Carnival Corp | CCL | 8,932.55 | 0.04% | 0.00% | 10.00% | 10.00% | 0.0040% |
| Cadence Design Systems Inc | CDNS | 20,104.78 | 0.09% | 0.00% | 12.50% | 12.50% | 0.0113% |
| CDW Corp/DE | CDW | 14,624.61 | 0.07% | 1.49% | 11.50% | 13.08% | 0.0086% |
| Celanese Corp | CE | 9,946.88 | 0.04% | 3.32% | 8.50% | 11.96% | 0.0053% |
| Cerner Corp | CERN | 20,847.30 | 0.09% | 1.08% | 9.50% | 10.63% | 0.0099% |
| CF Industries Holdings Inc | CF | 6,446.13 | 0.03% | 4.12% | 29.50% | 34.23% | 0.0099% |
| Citizens Financial Group Inc | CFG | 9,113.53 | 0.04% | 7.99% | 9.50% | 17.87% | 0.0073% |
| Church & Dwight Co Inc | CHD | 16,837.92 | 0.08% | 1.40% | 7.50% | 8.95% | 0.0068% |
| CH Robinson Worldwide Inc | CHRW | 9,841.77 | 0.04% | 2.80% | 8.00% | 10.91% | 0.0048% |
| Charter Communications Inc | CHTR | 97,413.70 | 0.44% | 0.00% | 33.50% | 33.50% | 0.1464% |
| Cigna Corp | CI | 69,539.20 | 0.31% | 0.02% | 14.00% | 14.02% | 0.0437% |
| Cincinnati Financial Corp | CINF | 13,248.47 | 0.06% | 2.96% | 11.00% | 14.12% | 0.0084% |
| Colgate-Palmolive Co | CL | 60,017.18 | 0.27% | 2.51% | 5.50% | 8.08% | 0.0217% |
| Clorox Co/The | CLX | 22,634.53 | 0.10% | 2.34% | 2.50% | 4.87% | 0.0049% |
| Comerica Inc | CMA | 4,759.37 | 0.02% | 8.24% | 8.00% | 16.57% | 0.0035% |
| Comcast Corp | CMCSA | 171,558.40 | 0.77% | 2.44% | 9.50% | 12.06% | 0.0928% |
| CME Group Inc | CME | 64,691.71 | 0.29% | 1.88% | 2.50% | 4.40% | 0.0128% |
| Chipotle Mexican Grill Inc | CMG | 20,125.71 | 0.09% | 0.00% | 17.50% | 17.50% | 0.0158% |
| Cummins Inc | CMI | 22,912.59 | 0.10% | 3.50% | 7.00% | 10.62% | 0.0109% |
| CMS Energy Corp | CMS | 17,213.51 | 0.08% | 2.74% | 7.50% | 10.34% | 0.0080% |
| Centene Corp | CNC | 27,040.38 | 0.12% | 0.00% | 13.00% | 13.00% | 0.0158% |
| CenterPoint Energy Inc | CNP | 8,447.71 | 0.04% | 3.57% | 6.50% | 10.19% | 0.0039% |
| Capital One Financial Corp | COF | 26,415.70 | 0.12% | 2.82% | 6.00% | 8.90% | 0.0105% |
| Cabot Oil & Gas Corp | COG | 7,828.06 | 0.04% | 2.08% | 40.50% | 43.00% | 0.0151% |
| Cooper Cos Inc/The | COO | 14,633.56 | 0.07% | 0.02% | 11.00% | 11.02% | 0.0072% |
| ConocoPhillips | COP | 38,708.09 | 0.17% | 4.71% | 37.00% | 42.58% | 0.0739% |
| Costco Wholesale Corp | COST | 135,123.10 | 0.61% | 0.94% | 11.00% | 11.99% | 0.0727% |
| Coty Inc | COTY | 4,471.74 | 0.02% | 8.50% | 4.50% | 13.19% | 0.0026% |
| Campbell Soup Co | CPB | 14,909.68 | 0.07% | 3.03% | 1.50% | 4.55% | 0.0030% |
| Capri Holdings Ltd | CPRI | 2,054.88 | 0.01% | 0.00% | 10.50% | 10.50% | 0.0010% |
| Copart Inc | CPRT | 16,817.19 | 0.08% | 0.00% | 16.00% | 16.00% | 0.0121% |
| salesforce.com Inc | CRM | 134,950.20 | 0.61% | 0.00% | 31.50% | 31.50% | 0.1906% |
| Cisco Systems Inc | CSCO | 177,019.30 | 0.79% | 3.45% | 7.00% | 10.57% | 0.0839% |
| CSX Corp | CSX | 49,130.88 | 0.22% | 1.64% | 12.00% | 13.74% | 0.0303% |
| Cintas Corp | CTAS | 20,015.84 | 0.09% | 1.51% | 15.00% | 16.62% | 0.0149% |
| CenturyLink Inc | CTL | 10,715.27 | 0.05% | 10.17% | 2.50% | 12.80% | 0.0061% |
| Cognizant Technology Solutions Corp | CTSH | 28,161.72 | 0.13% | 1.71% | 5.00% | 6.75% | 0.0085% |
| Corteva Inc | CTVA | 19,500.43 | N/A | 2.07% | N/A | N/A | N/A |
| Citrix Systems Inc | CTXS | 19,096.44 | 0.09% | 0.95% | 9.00% | 9.99% | 0.0086% |
| CVS Health Corp | CVS | 77,292.41 | 0.35% | 3.37% | 6.00% | 9.47% | 0.0328% |
| Chevron Corp | CVX | 161,828.80 | 0.73% | 6.00% | 13.50% | 19.91% | 0.1445% |
| Concho Resources Inc | CXO | 10,480.42 | 0.05% | 1.54% | 18.00% | 19.68% | 0.0092% |
| Dominion Energy Inc | D | 65,548.36 | 0.29% | 4.81% | 7.00% | 11.98% | 0.0352% |
| Delta Air Lines Inc | DAL | 15,023.84 | 0.07% | 0.00% | 9.50% | 9.50% | 0.0064% |
| DuPont de Nemours Inc | DD | 28,700.60 | N/A | 3.17% | N/A | N/A | N/A |
| Deere & Co | DE | 46,030.00 | 0.21% | 2.07% | 10.00% | 12.17% | 0.0251% |
| Discover Financial Services | DFS | 11,544.04 | 0.05% | 4.73% | 7.50% | 12.41% | 0.0064% |
| Dollar General Corp | DG | 43,083.41 | 0.19% | 0.85% | 12.00% | 12.90% | 0.0249% |
| Quest Diagnostics Inc | DGX | 11,682.72 | 0.05% | 2.55% | 9.00% | 11.66% | 0.0061% |
| DR Horton Inc | DHI | 14,522.72 | 0.07% | 1.77% | 7.00% | 8.83% | 0.0058% |
| Danaher Corp | DHR | 100,937.90 | 0.45% | 0.50% | 15.00% | 15.54% | 0.0703% |
| Walt Disney Co/The | DIS | 180,005.70 | 0.81% | 1.74% | 7.50% | 9.31% | 0.0751% |
| Discovery Inc | DISCA | 11,372.66 | 0.05% | 0.00% | 18.00% | 18.00% | 0.0092% |
| DISH Network Corp | DISH | 11,391.79 | 0.05% | 0.00% | -1.00% | -1.00% | -0.0005% |
| Digital Realty Trust Inc | DLR | 30,098.97 | 0.13% | 3.07% | 6.00% | 9.16% | 0.0124% |
| Dollar Tree Inc | DLTR | 18,751.37 | 0.08% | 0.00% | 10.00% | 10.00% | 0.0084% |
| Dover Corp | DOV | 13,015.83 | 0.06% | 2.19% | 9.50% | 11.79% | 0.0069% |
| Dow Inc | DOW | 25,796.72 | N/A | 8.19% | N/A | N/A | N/A |
| Duke Realty Corp | DRE | 11,992.80 | 0.05% | 2.87% | -1.00% | 1.86% | 0.0010% |
| Darden Restaurants Inc | DRI | 7,680.72 | 0.03% | 0.00% | 11.00% | 11.00% | 0.0038% |
| DTE Energy Co | DTE | 19,958.88 | 0.09% | 4.05% | 5.00% | 9.15% | 0.0082% |
| Duke Energy Corp | DUK | 62,671.50 | 0.28% | 4.48% | 6.00% | 10.61% | 0.0298% |
| DaVita Inc | DVA | 9,684.80 | 0.04% | 0.00% | 11.50% | 11.50% | 0.0050% |
| Devon Energy Corp | DVN | 3,638.85 | 0.02% | 5.10% | 16.50% | 22.02% | 0.0036% |
| DXC Technology Co | DXC | 4,004.87 | 0.02% | 5.32% | 10.00% | 15.59% | 0.0028% |
| Electronic Arts Inc | EA | 31,037.04 | 0.14% | 0.00% | 10.50% | 10.50% | 0.0146% |
| eBay Inc | EBAY | 26,275.96 | 0.12% | 1.94% | 10.00% | 12.04% | 0.0142% |
| Ecolab Inc | ECL | 49,227.44 | 0.22% | 1.10% | 8.50% | 9.65% | 0.0213% |
| Consolidated Edison Inc | ED | 27,915.39 | 0.13% | 3.69% | 3.50% | 7.25% | 0.0091% |
| Equifax Inc | EFX | 14,868.82 | 0.07% | 1.27% | 7.50% | 8.82% | 0.0059% |
| Edison International | EIX | 20,839.48 | 0.09% | 4.48% | 14.00% | 18.79% | 0.0176% |
| Estee Lauder Cos Inc/The | EL | 59,562.70 | 0.27% | 1.19% | 13.00% | 14.27% | 0.0381% |
| Eastman Chemical Co | EMN | 7,686.16 | 0.03% | 4.67% | 5.00% | 9.79% | 0.0034% |
| Emerson Electric Co | EMR | 31,833.10 | 0.14% | 3.84% | 9.00% | 13.01% | 0.0186% |
| EOG Resources Inc | EOG | 26,348.68 | 0.12% | 3.31% | 26.50% | 30.25% | 0.0357% |
| Equinix Inc | EQIX | 56,666.69 | 0.25% | 1.63% | 16.00% | 17.76% | 0.0451% |
| Equity Residential | EQR | 24,103.68 | 0.11% | 3.72% | -11.50% | -7.99% | -0.0086% |
| Eversource Energy | ES | 27,495.50 | 0.12% | 2.72% | 5.50% | 8.29% | 0.0102% |
| Essex Property Trust Inc | ESS | 15,426.17 | 0.07% | 3.58% | 1.00% | 4.60% | 0.0032% |
| E*TRADE Financial Corp | ETFC | 8,887.07 | 0.04% | 1.40% | 5.50% | 6.94% | 0.0028% |
| Eaton Corp PLC | ETN | 33,129.88 | 0.15% | 3.64% | 6.50% | 10.26% | 0.0152% |
| Entergy Corp | ETR | 20,018.36 | 0.09% | 3.74% | 3.00% | 6.80% | 0.0061% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Evergy Inc | EVRG | 13,793.37 | N/A | 3.42% | N/A | N/A | N/A |
| Edwards Lifesciences Corp | EW | 43,294.15 | 0.19% | 0.00% | 15.00% | 15.00% | 0.0291% |
| Exelon Corp | EXC | 36,575.07 | 0.16% | 4.07% | 8.00% | 12.23% | 0.0201% |
| Expeditors International of Washington I | EXPD | 12,337.51 | 0.06% | 1.38% | 7.50% | 8.93% | 0.0049% |
| Expedia Group Inc | EXPE | 8,809.42 | 0.04% | 2.25% | 24.00% | 26.52% | 0.0105% |
| Extra Space Storage Inc | EXR | 12,480.34 | 0.06% | 3.75% | 3.00% | 6.81% | 0.0038% |
| Ford Motor Co | F | 19,587.04 | 0.09% | 0.00% | 2.50% | 2.50% | 0.0022% |
| Diamondback Energy Inc | FANG | 5,959.40 | 0.03% | 4.00% | 17.00% | 21.34% | 0.0057% |
| Fastenal Co | FAST | 18,633.86 | 0.08% | 3.08% | 9.00% | 12.22% | 0.0102% |
| Facebook Inc | FB | 497,046.60 | 2.23% | 0.00% | 17.50% | 17.50% | 0.3901% |
| Fortune Brands Home & Security Inc | FBHS | 6,580.45 | 0.03% | 2.03% | 7.50% | 9.61% | 0.0028% |
| Freeport-McMoRan Inc | FCX | 11,651.53 | 0.05% | 0.00% | 19.50% | 19.50% | 0.0102% |
| FedEx Corp | FDX | 32,797.20 | 0.15% | 2.07% | 5.00% | 7.12% | 0.0105% |
| FirstEnergy Corp | FE | 23,372.39 | 0.10% | 3.63% | 7.00% | 10.76% | 0.0113% |
| F5 Networks Inc | FFIV | 7,351.08 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0033% |
| Fidelity National Information Services I | FIS | 76,608.78 | 0.34% | 1.12% | 23.50% | 24.75% | 0.0850% |
| Fiserv Inc | FISV | 66,970.30 | 0.30% | 0.00% | 15.00% | 15.00% | 0.0451% |
| Fifth Third Bancorp | FITB | 11,831.81 | 0.05% | 6.47% | 6.50% | 13.18% | 0.0070% |
| FLIR Systems Inc | FLIR | 4,683.63 | 0.02% | 2.04% | 9.00% | 11.13% | 0.0023% |
| Flowserve Corp | FLS | 3,751.46 | 0.02% | 2.78% | 12.50% | 15.45% | 0.0026% |
| FleetCor Technologies Inc | FLT | 19,116.52 | 0.09% | 0.00% | 16.50% | 16.50% | 0.0141% |
| FMC Corp | FMC | 10,700.50 | 0.05% | 2.17% | 11.00% | 13.29% | 0.0064% |
| Fox Corp | FOXA | 16,056.75 | N/A | 1.75% | N/A | N/A | N/A |
| First Republic Bank/CA | FRC | 15,733.23 | 0.07% | 0.81% | 10.50% | 11.35% | 0.0080% |
| Federal Realty Investment Trust | FRT | 6,063.68 | 0.03% | 5.28% | 1.50% | 6.82% | 0.0019% |
| TechnipFMC PLC | FTI | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Fortinet Inc | FTNT | 18,702.53 | 0.08% | 0.00% | 28.00% | 28.00% | 0.0235% |
| Fortive Corp | FTV | 20,356.85 | 0.09% | 0.46% | 8.00% | 8.48% | 0.0077% |
| General Dynamics Corp | GD | 39,791.86 | 0.18% | 3.20% | 7.00% | 10.31% | 0.0184% |
| General Electric Co | GE | 63,790.57 | 0.29% | 0.55% | 8.00% | 8.57% | 0.0245% |
| Gilead Sciences Inc | GILD | 94,937.34 | 0.43% | 3.63% | -1.50% | 2.10% | 0.0090% |
| General Mills Inc | GIS | 33,761.23 | 0.15% | 3.57% | 4.00% | 7.64% | 0.0116% |
| Globe Life Inc | GL | 8,101.62 | 0.04% | 1.00% | 9.00% | 10.05% | 0.0036% |
| Corning Inc | GLW | 15,674.34 | 0.07% | 4.28% | 13.50% | 18.07% | 0.0127% |
| General Motors Co | GM | 32,382.00 | 0.15% | 6.74% | 2.50% | 9.32% | 0.0135% |
| Alphabet Inc | GOOGL | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Genuine Parts Co | GPC | 10,642.71 | 0.05% | 4.31% | 7.00% | 11.46% | 0.0055% |
| Global Payments Inc | GPN | 44,820.59 | 0.20% | 0.52% | 20.50% | 21.07% | 0.0424% |
| Gap Inc/The | GPS | 2,912.35 | 0.01% | 0.00% | 3.00% | 3.00% | 0.0004% |
| Garmin Ltd | GRMN | 14,751.47 | 0.07% | 3.15% | 7.00% | 10.26% | 0.0068% |
| Goldman Sachs Group Inc/The | GS | 61,465.81 | 0.28% | 2.83% | 6.50% | 9.42% | 0.0260% |
| WW Grainger Inc | GWW | 14,517.24 | 0.07% | 2.13% | 8.00% | 10.22% | 0.0067% |
| Halliburton Co | HAL | 7,682.50 | 0.03% | 8.23% | 19.50% | 28.53% | 0.0098% |
| Hasbro Inc | HAS | 9,361.66 | 0.04% | 3.67% | 9.50% | 13.34% | 0.0056% |
| Huntington Bancshares Inc/OH | HBAN | 8,986.23 | 0.04% | 7.15% | 9.00% | 16.47% | 0.0066% |
| Hanesbrands Inc | HBI | 3,330.45 | 0.01% | 6.52% | 3.00% | 9.62% | 0.0014% |
| HCA Healthcare Inc | HCA | 36,572.37 | 0.16% | 1.59% | 10.50% | 12.17% | 0.0200% |
| Home Depot Inc/The | HD | 212,353.80 | 0.95% | 3.08% | 8.00% | 11.20% | 0.1067% |
| Hess Corp | HES | 11,857.08 | N/A | 2.55% | N/A | N/A | N/A |
| HollyFrontier Corp | HFC | 4,310.41 | 0.02% | 5.26% | 16.50% | 22.19% | 0.0043% |
| Hartford Financial Services Group Inc/Th | HIG | 13,970.04 | 0.06% | 3.36% | 12.50% | 16.07% | 0.0101% |
| Huntington Ingalls Industries Inc | HII | 8,013.04 | 0.04% | 2.11% | 6.00% | 8.17% | 0.0029% |
| Hilton Worldwide Holdings Inc | HLT | 23,277.24 | 0.10% | 0.00% | 17.00% | 17.00% | 0.0177% |
| Harley-Davidson Inc | HOG | 2,874.02 | 0.01% | 8.06% | 8.50% | 16.90% | 0.0022% |
| Hologic Inc | HOLX | 10,391.48 | 0.05% | 0.00% | 8.00% | 8.00% | 0.0037% |
| Honeywell International Inc | HON | 99,020.67 | 0.44% | 2.59% | 8.00% | 10.69% | 0.0475% |
| Helmerich & Payne Inc | HP | 2,043.62 | N/A | 5.33% | N/A | N/A | N/A |
| Hewlett Packard Enterprise Co | HPE | 13,227.39 | 0.06% | 4.89% | 7.50% | 12.57% | 0.0075% |
| HP Inc | HPQ | 22,526.76 | 0.10% | 4.58% | 10.50% | 15.32% | 0.0155% |
| H&R Block Inc | HRB | 2,802.42 | 0.01% | 7.35% | 7.00% | 14.61% | 0.0018% |
| Hormel Foods Corp | HRL | 25,457.35 | 0.11% | 2.07% | 8.50% | 10.66% | 0.0122% |
| Henry Schein Inc | HSIC | 7,659.38 | 0.03% | 0.00% | 6.50% | 6.50% | 0.0022% |
| Host Hotels & Resorts Inc | HST | 8,336.90 | 0.04% | 7.11% | -2.50% | 4.52% | 0.0017% |
| Hershey Co/The | HSY | 29,801.98 | 0.13% | 2.28% | 4.50% | 6.83% | 0.0091% |
| Humana Inc | HUM | 44,553.73 | 0.20% | 0.74% | 10.50% | 11.28% | 0.0225% |
| Howmet Aerospace Inc | HWM | 5,661.74 | 0.03% | 0.00% | 12.00% | 12.00% | 0.0030% |
| International Business Machines Corp | IBM | 105,823.30 | 0.47% | 5.53% | 1.50% | 7.07% | 0.0336% |
| Intercontinental Exchange Inc | ICE | 51,545.36 | 0.23% | 1.41% | 9.00% | 10.47% | 0.0242% |
| IDEXX Laboratories Inc | IDXX | 21,878.25 | 0.10% | 0.00% | 12.50% | 12.50% | 0.0123% |
| IDEX Corp | IEX | 11,481.59 | 0.05% | 1.33% | 7.50% | 8.88% | 0.0046% |
| International Flavors & Fragrances Inc | IFF | 12,946.59 | 0.06% | 2.56% | 7.50% | 10.16% | 0.0059% |
| Illumina Inc | ILMN | 41,305.53 | 0.19% | 0.00% | 12.00% | 12.00% | 0.0222% |
| Incyte Corp | INCY | 19,022.01 | 0.09% | 0.00% | 64.50% | 64.50% | 0.0550% |
| IHS Markit Ltd | INFO | 25,294.06 | 0.11% | 1.06% | 12.00% | 13.12% | 0.0149% |
| Intel Corp | INTC | 256,563.00 | 1.15% | 2.24% | 9.00% | 11.34% | 0.1305% |
| Intuit Inc | INTU | 64,068.95 | 0.29% | 0.91% | 14.50% | 15.48% | 0.0445% |
| International Paper Co | IP | 12,986.35 | 0.06% | 6.19% | 6.50% | 12.89% | 0.0075% |
| Interpublic Group of Cos Inc/The | IPG | 6,153.30 | 0.03% | 6.42% | 11.00% | 17.77% | 0.0049% |
| IPG Photonics Corp | IPGP | 6,378.38 | 0.03% | 0.00% | 9.50% | 9.50% | 0.0027% |
| IQVIA Holdings Inc | IQV | 24,594.39 | 0.11% | 0.00% | 9.50% | 9.50% | 0.0105% |
| Ingersoll Rand Inc | IR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Iron Mountain Inc | IRM | 7,451.15 | 0.03% | 9.56% | 7.50% | 17.42% | 0.0058% |
| Intuitive Surgical Inc | ISRG | 59,013.80 | 0.26% | 0.00% | 14.00% | 14.00% | 0.0371% |
| Gartner Inc | IT | 9,358.92 | 0.04% | 0.00% | 12.50% | 12.50% | 0.0052% |
| Illinois Tool Works Inc | ITW | 51,038.32 | 0.23% | 2.70% | 8.00% | 10.81% | 0.0247% |
| Invesco Ltd | IVZ | 4,298.38 | 0.02% | 13.09% | 6.00% | 19.48% | 0.0038% |
| Jacobs Engineering Group Inc | J | 10,765.10 | 0.05% | 0.94% | 14.00% | 15.01% | 0.0072% |
| JB Hunt Transport Services Inc | JBHT | 10,533.10 | 0.05% | 1.10% | 7.50% | 8.64% | 0.0041% |
| Johnson Controls International plc | JCI | 22,394.22 | 0.10% | 3.55% | 5.50% | 9.15% | 0.0092% |
| Jack Henry & Associates Inc | JKHY | 12,993.82 | 0.06% | 1.02% | 12.00% | 13.08% | 0.0076% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Johnson & Johnson | JNJ | 376,911.50 | 1.69% | 2.65% | 11.50% | 14.30% | 0.2418% |
| Juniper Networks Inc | JNPR | 7,473.78 | 0.03% | 3.60% | 6.00% | 9.71% | 0.0033% |
| JPMorgan Chase & Co | JPM | 290,823.20 | 1.30% | 3.92% | 8.50% | 12.59% | 0.1642% |
| Nordstrom Inc | JWN | 2,948.80 | 0.01% | 0.00% | 5.00% | 5.00% | 0.0007% |
| Kellogg Co | K | 20,991.23 | 0.09% | 3.74% | 3.00% | 6.80% | 0.0064% |
| KeyCorp | KEY | 11,071.54 | 0.05% | 6.71% | 10.50% | 17.56% | 0.0087% |
| Keysight Technologies Inc | KEYS | 17,094.26 | 0.08% | 0.00% | 21.00% | 21.00% | 0.0161% |
| Kraft Heinz Co/The | KHC | 33,357.72 | 0.15% | 5.86% | -0.50% | 5.35% | 0.0080% |
| Kimco Realty Corp | KIM | 4,158.38 | 0.02% | 11.84% | 5.00% | 17.14% | 0.0032% |
| KLA Corp | KLAC | 23,887.35 | 0.11% | 2.23% | 11.50% | 13.86% | 0.0148% |
| Kimberly-Clark Corp | KMB | 45,296.57 | 0.20% | 3.23% | 7.00% | 10.34% | 0.0210% |
| Kinder Morgan Inc | KMI | 33,589.00 | 0.15% | 6.74% | 22.00% | 29.48% | 0.0444% |
| CarMax Inc | KMX | 10,355.12 | 0.05% | 0.00% | 10.50% | 10.50% | 0.0049% |
| Coca-Cola Co/The | KO | 204,669.60 | 0.92% | 3.43% | 6.50% | 10.04% | 0.0922% |
| Kroger Co/The | KR | 24,443.76 | 0.11% | 2.26% | 5.50% | 7.82% | 0.0086% |
| Kohl's Corp | KSS | 2,750.64 | 0.01% | 16.90% | 6.50% | 23.95% | 0.0030% |
| Kansas City Southern | KSU | 13,850.76 | 0.06% | 1.15% | 12.00% | 13.22% | 0.0082% |
| Loews Corp | L | 11,361.61 | 0.05% | 0.66% | 14.00% | 14.71% | 0.0075% |
| L Brands Inc | LB | 4,024.08 | 0.02% | 0.00% | -2.50% | -2.50% | -0.0005% |
| Leidos Holdings Inc | LDOS | 13,457.04 | 0.06% | 1.43% | 9.00% | 10.49% | 0.0063% |
| Leggett & Platt Inc | LEG | 3,791.89 | 0.02% | 5.56% | 8.00% | 13.78% | 0.0023% |
| Lennar Corp | LEN | 13,538.77 | 0.06% | 1.15% | 7.00% | 8.19% | 0.0050% |
| Laboratory Corp of America Holdings | LH | 13,748.98 | 0.06% | 0.00% | 8.00% | 8.00% | 0.0049% |
| L3Harris Technologies Inc | LHX | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Linde PLC | LIN | 100,547.00 | N/A | 2.06% | N/A | N/A | N/A |
| LKQ Corp | LKQ | 6,740.84 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0030% |
| Eli Lilly & Co | LLY | 140,009.50 | 0.63% | 2.02% | 10.00% | 12.12% | 0.0761% |
| Lockheed Martin Corp | LMT | 101,194.80 | 0.45% | 2.71% | 8.50% | 11.33% | 0.0514% |
| Lincoln National Corp | LNC | 6,403.51 | 0.03% | 5.16% | 9.50% | 14.91% | 0.0043% |
| Alliant Energy Corp | LNT | 12,552.53 | 0.06% | 2.97% | 5.50% | 8.55% | 0.0048% |
| Lowe's Cos Inc | LOW | 72,460.80 | 0.32% | 2.49% | 10.50% | 13.12% | 0.0426% |
| Lam Research Corp | LRCX | 38,001.74 | 0.17% | 1.72% | 10.00% | 11.81% | 0.0201% |
| Southwest Airlines Co | LUV | 17,803.90 | 0.08% | 2.10% | 10.00% | 12.21% | 0.0097% |
| Las Vegas Sands Corp | LVS | 35,540.23 | 0.16% | 6.79% | 7.50% | 14.54% | 0.0232% |
| Lamb Weston Holdings Inc | LW | 8,433.75 | 0.04% | 1.65% | 9.50% | 11.23% | 0.0042% |
| LyondellBasell Industries NV | LYB | 18,494.14 | 0.08% | 7.57% | 3.00% | 10.68% | 0.0089% |
| Live Nation Entertainment Inc | LYV | 8,069.92 | N/A | 0.00% | N/A | N/A | N/A |
| Mastercard Inc | MA | 273,659.50 | 1.23% | 0.59% | 16.00% | 16.64% | 0.2042% |
| Mid-America Apartment Communities Inc | MAA | 12,628.71 | 0.06% | 3.61% | 0.50% | 4.12% | 0.0023% |
| Marriott International Inc/MD | MAR | 26,979.06 | 0.12% | 0.00% | 11.50% | 11.50% | 0.0139% |
| Masco Corp | MAS | 10,897.22 | 0.05% | 1.47% | 7.00% | 8.52% | 0.0042% |
| McDonald's Corp | MCD | 132,460.80 | 0.59% | 2.87% | 8.00% | 10.98% | 0.0653% |
| Microchip Technology Inc | MCHP | 19,047.82 | 0.09% | 1.89% | 7.50% | 9.46% | 0.0081% |
| McKesson Corp | MCK | 23,286.12 | 0.10% | 1.25% | 9.00% | 10.31% | 0.0108% |
| Moody's Corp | MCO | 42,514.86 | 0.19% | 0.99% | 10.50% | 11.54% | 0.0220% |
| Mondelez International Inc | MDLZ | 74,318.96 | 0.33% | 2.32% | 8.00% | 10.41% | 0.0347% |
| Medtronic PLC | MDT | 133,113.20 | 0.60% | 2.22% | 7.50% | 9.80% | 0.0585% |
| MetLife Inc | MET | 30,636.36 | 0.14% | 5.26% | 7.50% | 12.96% | 0.0178% |
| MGM Resorts International | MGM | 7,547.22 | 0.03% | 4.00% | 14.00% | 18.28% | 0.0062% |
| Mohawk Industries Inc | MHK | 6,113.29 | N/A | 0.00% | N/A | N/A | N/A |
| McCormick & Co Inc/MD | MKC | 19,815.99 | 0.09% | 1.66% | 6.50% | 8.21% | 0.0073% |
| MarketAxess Holdings Inc | MKTX | 15,007.84 | 0.07% | 0.61% | 13.50% | 14.15% | 0.0095% |
| Martin Marietta Materials Inc | MLM | 12,278.45 | 0.06% | 1.13% | 10.50% | 11.69% | 0.0064% |
| Marsh & McLennan Cos Inc | MMC | 47,272.86 | 0.21% | 1.97% | 9.00% | 11.06% | 0.0234% |
| 3M Co | MMM | 85,676.84 | 0.38% | 3.95% | 4.50% | 8.54% | 0.0328% |
| Monster Beverage Corp | MNST | 32,341.42 | 0.15% | 0.00% | 11.50% | 11.50% | 0.0167% |
| Altria Group Inc | MO | 74,560.81 | 0.33% | 8.37% | 6.00% | 14.62% | 0.0489% |
| Mosaic Co/The | MOS | 4,593.06 | 0.02% | 1.86% | 22.00% | 24.06% | 0.0050% |
| Marathon Petroleum Corp | MPC | 15,801.50 | 0.07% | 9.54% | 9.00% | 18.97% | 0.0134% |
| Merck & Co Inc | MRK | 207,234.50 | 0.93% | 2.99% | 9.00% | 12.12% | 0.1127% |
| Marathon Oil Corp | MRO | 3,163.95 | N/A | 5.06% | N/A | N/A | N/A |
| Morgan Stanley | MS | 62,754.72 | 0.28% | 3.56% | 5.00% | 8.65% | 0.0243% |
| MSCI Inc | MSCI | 25,173.23 | 0.11% | 0.97% | 19.50% | 20.56% | 0.0232% |
| Microsoft Corp | MSFT | 1,256,805.00 | 5.64% | 1.24% | 15.50% | 16.84% | 0.9490% |
| Motorola Solutions Inc | MSI | 25,268.67 | 0.11% | 1.81% | 9.50% | 11.40% | 0.0129% |
| M&T Bank Corp | MTB | 14,056.60 | 0.06% | 4.09% | 9.50% | 13.78% | 0.0087% |
| Mettler-Toledo International Inc | MTD | 18,046.07 | 0.08% | 0.00% | 10.50% | 10.50% | 0.0085% |
| Micron Technology Inc | MU | 53,698.48 | 0.24% | 0.00% | 13.50% | 13.50% | 0.0325% |
| Maxim Integrated Products Inc | MXIM | 14,382.70 | 0.06% | 3.60% | 4.50% | 8.18% | 0.0053% |
| Mylan NV | MYL | 7,814.37 | 0.04% | 0.00% | 3.00% | 3.00% | 0.0011% |
| Noble Energy Inc | NBL | 3,453.31 | N/A | 6.65% | N/A | N/A | N/A |
| Norwegian Cruise Line Holdings Ltd | NCLH | 2,497.32 | 0.01% | 0.00% | 16.00% | 16.00% | 0.0018% |
| Nasdaq Inc | NDAQ | 17,191.24 | 0.08% | 1.81% | 6.00% | 7.86% | 0.0061% |
| NextEra Energy Inc | NEE | 114,181.50 | 0.51% | 2.42% | 10.00% | 12.54% | 0.0642% |
| Newmont Corp | NEM | 40,828.24 | 0.18% | 1.98% | 11.00% | 13.09% | 0.0240% |
| Netflix Inc | NFLX | 162,850.00 | 0.73% | 0.00% | 32.00% | 32.00% | 0.2337% |
| NiSource Inc | NI | 9,511.70 | 0.04% | 3.30% | 14.00% | 17.53% | 0.0075% |
| NIKE Inc | NKE | 132,641.50 | 0.59% | 1.15% | 17.50% | 18.75% | 0.1115% |
| NortonLifeLock Inc | NLOK | 12,022.12 | 0.05% | 2.55% | 5.00% | 7.61% | 0.0041% |
| Nielsen Holdings PLC | NLSN | 5,306.64 | 0.02% | 1.61% | 41.00% | 42.94% | 0.0102% |
| Northrop Grumman Corp | NOC | 55,264.89 | 0.25% | 1.60% | 10.00% | 11.68% | 0.0289% |
| National Oilwell Varco Inc | NOV | 4,506.73 | N/A | 1.71% | N/A | N/A | N/A |
| ServiceNow Inc | NOW | 51,674.59 | N/A | 0.00% | N/A | N/A | N/A |
| NRG Energy Inc | NRG | 7,420.99 | N/A | 4.08% | N/A | N/A | N/A |
| Norfolk Southern Corp | NSC | 40,999.16 | 0.18% | 2.37% | 13.00% | 15.52% | 0.0285% |
| NetApp Inc | NTAP | 9,097.56 | 0.04% | 5.12% | 10.00% | 15.38% | 0.0063% |
| Northern Trust Corp | NTRS | 17,666.72 | 0.08% | 3.36% | 7.50% | 10.99% | 0.0087% |
| Nucor Corp | NUE | 11,801.50 | 0.05% | 4.12% | 11.00% | 15.35% | 0.0081% |
| NVIDIA Corp | NVDA | 163,373.40 | 0.73% | 0.24% | 10.00% | 10.25% | 0.0751% |
| NVR Inc | NVR | 10,661.58 | 0.05% | 0.00% | 9.50% | 9.50% | 0.0045% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Newell Brands Inc | NWL | 5,704.55 | 0.03% | 6.83% | 6.00% | 13.03% | 0.0033% |
| News Corp | NWSA | 5,264.68 | N/A | 2.24% | N/A | N/A | N/A |
| Realty Income Corp | O | 16,137.81 | 0.07% | 5.33% | 6.50% | 12.00% | 0.0087% |
| Old Dominion Freight Line Inc | ODFL | 16,571.93 | 0.07% | 0.46% | 9.00% | 9.48% | 0.0070% |
| ONEOK Inc | OKE | 10,925.86 | 0.05% | 14.75% | 16.00% | 31.93% | 0.0156% |
| Omnicom Group Inc | OMC | 11,868.86 | 0.05% | 5.12% | 6.50% | 11.79% | 0.0063% |
| Oracle Corp | ORCL | 164,782.90 | 0.74% | 1.84% | 10.00% | 11.93% | 0.0882% |
| O'Reilly Automotive Inc | ORLY | 25,712.39 | 0.12% | 0.00% | 12.00% | 12.00% | 0.0138% |
| Otis Worldwide Corp | OTIS | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Occidental Petroleum Corp | OXY | 13,900.01 | 0.06% | 2.83% | 20.50% | 23.62% | 0.0147% |
| Paycom Software Inc | PAYC | 11,680.15 | 0.05% | 0.00% | 26.00% | 26.00% | 0.0136% |
| Paychex Inc | PAYX | 23,337.02 | 0.10% | 4.18% | 10.50% | 14.90% | 0.0156% |
| People's United Financial Inc | PBCT | 4,968.32 | 0.02% | 6.43% | 4.00% | 10.56% | 0.0024% |
| PACCAR Inc | PCAR | 22,975.22 | 0.10% | 4.21% | 6.00% | 10.34% | 0.0107% |
| Healthpeak Properties Inc | PEAK | 12,739.59 | 0.06% | 5.55% | -15.50% | -10.38% | -0.0059% |
| Public Service Enterprise Group Inc | PEG | 25,633.44 | 0.11% | 3.85% | 6.00% | 9.97% | 0.0115% |
| PepsiCo Inc | PEP | 184,460.50 | 0.83% | 3.08% | 6.00% | 9.17% | 0.0759% |
| Pfizer Inc | PFE | 191,476.40 | 0.86% | 4.39% | 8.50% | 13.08% | 0.1123% |
| Principal Financial Group Inc | PFG | 8,462.32 | 0.04% | 7.36% | 5.50% | 13.06% | 0.0050% |
| Procter & Gamble Co/The | PG | 284,234.10 | 1.27% | 2.59% | 8.50% | 11.20% | 0.1428% |
| Progressive Corp/The | PGR | 45,487.73 | 0.20% | 0.51% | 13.50% | 14.04% | 0.0287% |
| Parker-Hannifin Corp | PH | 18,149.25 | 0.08% | 2.49% | 9.00% | 11.60% | 0.0094% |
| PulteGroup Inc | PHM | 6,896.40 | 0.03% | 1.96% | 7.50% | 9.53% | 0.0029% |
| Packaging Corp of America | PKG | 8,314.50 | 0.04% | 3.87% | 4.00% | 7.95% | 0.0030% |
| PerkinElmer Inc | PKI | 8,655.58 | 0.04% | 0.36% | 10.00% | 10.38% | 0.0040% |
| Prologis Inc | PLD | 54,448.26 | 0.24% | 2.74% | 6.00% | 8.82% | 0.0215% |
| Philip Morris International Inc | PM | 116,163.10 | 0.52% | 6.27% | 5.50% | 11.94% | 0.0622% |
| PNC Financial Services Group Inc/The | PNC | 43,083.50 | 0.19% | 4.62% | 8.00% | 12.80% | 0.0247% |
| Pentair PLC | PNR | 5,501.50 | 0.02% | 2.33% | 6.00% | 8.40% | 0.0021% |
| Pinnacle West Capital Corp | PNW | 8,867.83 | 0.04% | 4.08% | 4.00% | 8.16% | 0.0032% |
| PPG Industries Inc | PPG | 22,000.73 | 0.10% | 2.19% | 6.00% | 8.26% | 0.0081% |
| PPL Corp | PPL | 19,802.29 | 0.09% | 6.43% | 2.50% | 9.01% | 0.0080% |
| Perrigo Co PLC | PRGO | 6,648.49 | 0.03% | 1.90% | 3.50% | 5.43% | 0.0016% |
| Prudential Financial Inc | PRU | 21,943.73 | 0.10% | 8.00% | 7.00% | 15.28% | 0.0150% |
| Public Storage | PSA | 34,664.26 | 0.16% | 4.02% | 3.50% | 7.59% | 0.0118% |
| Phillips 66 | PSX | 28,305.60 | 0.13% | 6.28% | 9.00% | 15.56% | 0.0198% |
| PVH Corp | PVH | 3,462.11 | 0.02% | 0.00% | 9.00% | 9.00% | 0.0014% |
| Quanta Services Inc | PWR | 4,811.80 | 0.02% | 0.59% | 15.00% | 15.63% | 0.0034% |
| Pioneer Natural Resources Co | PXD | 13,299.47 | 0.06% | 2.74% | 35.00% | 38.22% | 0.0228% |
| PayPal Holdings Inc | PYPL | 123,340.40 | 0.55% | 0.00% | 20.00% | 20.00% | 0.1106% |
| QUALCOMM Inc | QCOM | 83,816.20 | 0.38% | 3.55% | 9.50% | 13.22% | 0.0497% |
| Qorvo Inc | QRVO | 10,071.52 | 0.05% | 0.00% | 53.00% | 53.00% | 0.0239% |
| Royal Caribbean Cruises Ltd | RCL | 7,842.57 | 0.04% | 8.31% | 12.50% | 21.33% | 0.0075% |
| Everest Re Group Ltd | RE | 8,058.57 | 0.04% | 3.13% | 9.50% | 12.78% | 0.0046% |
| Regency Centers Corp | REG | 6,865.64 | 0.03% | 5.82% | 13.50% | 19.71% | 0.0061% |
| Regeneron Pharmaceuticals Inc | REGN | 56,498.21 | 0.25% | 0.00% | 6.00% | 6.00% | 0.0152% |
| Regions Financial Corp | RF | 9,679.12 | 0.04% | 6.33% | 10.00% | 16.65% | 0.0072% |
| Robert Half International Inc | RHI | 4,806.42 | 0.02% | 3.33% | 8.00% | 11.46% | 0.0025% |
| Raymond James Financial Inc | RJF | 9,253.21 | 0.04% | 2.25% | 6.50% | 8.82% | 0.0037% |
| Ralph Lauren Corp | RL | 5,612.99 | 0.03% | 3.61% | 8.00% | 11.75% | 0.0030% |
| ResMed Inc | RMD | 22,435.98 | 0.10% | 1.01% | 14.50% | 15.58% | 0.0157% |
| Rockwell Automation Inc | ROK | 19,498.36 | 0.09% | 2.44% | 7.00% | 9.53% | 0.0083% |
| Rollins Inc | ROL | 11,758.44 | 0.05% | 1.34% | 11.00% | 12.41% | 0.0065% |
| Roper Technologies Inc | ROP | 33,112.13 | 0.15% | 0.64% | 8.00% | 8.67% | 0.0129% |
| Ross Stores Inc | ROST | 32,002.61 | 0.14% | 1.28% | 9.50% | 10.84% | 0.0156% |
| Republic Services Inc | RSG | 27,642.19 | 0.12% | 2.15% | 10.00% | 12.26% | 0.0152% |
| Raytheon Technologies Corp | RTX | 54,126.60 | 0.24% | 4.70% | 8.00% | 12.89% | 0.0313% |
| SBA Communications Corp | SBAC | 34,013.16 | 0.15% | 0.62% | 31.50% | 32.22% | 0.0491% |
| Starbucks Corp | SBUX | 84,058.98 | 0.38% | 2.43% | 13.50% | 16.09% | 0.0607% |
| Charles Schwab Corp/The | SCHW | 46,916.10 | 0.21% | 1.97% | 6.50% | 8.53% | 0.0180% |
| Sealed Air Corp | SEE | 4,417.53 | 0.02% | 2.24% | 26.00% | 28.53% | 0.0057% |
| Sherwin-Williams Co/The | SHW | 44,994.84 | 0.20% | 1.10% | 8.50% | 9.65% | 0.0195% |
| SVB Financial Group | SIVB | 8,691.31 | 0.04% | 0.00% | 15.00% | 15.00% | 0.0058% |
| JM Smucker Co/The | SJM | 13,015.50 | 0.06% | 3.11% | 3.00% | 6.16% | 0.0036% |
| Schlumberger Ltd | SLB | 23,924.42 | 0.11% | 11.57% | 15.00% | 27.44% | 0.0294% |
| SL Green Realty Corp | SLG | 4,128.48 | 0.02% | 7.27% | 0.50% | 7.79% | 0.0014% |
| Snap-on Inc | SNA | 6,385.17 | 0.03% | 3.71% | 5.50% | 9.31% | 0.0027% |
| Synopsys Inc | SNPS | 20,855.55 | 0.09% | 0.00% | 12.50% | 12.50% | 0.0117% |
| Southern Co/The | SO | 61,278.14 | 0.27% | 4.40% | 4.00% | 8.49% | 0.0233% |
| Simon Property Group Inc | SPG | 19,439.76 | N/A | 13.35% | N/A | N/A | N/A |
| S&P Global Inc | SPGI | 63,913.05 | 0.29% | 1.03% | 11.00% | 12.09% | 0.0346% |
| Sempra Energy | SRE | 35,603.45 | 0.16% | 3.44% | 11.00% | 14.63% | 0.0234% |
| STERIS PLC | STE | 12,655.06 | 0.06% | 0.99% | 9.50% | 10.54% | 0.0060% |
| State Street Corp | STT | 20,750.27 | 0.09% | 3.65% | 5.50% | 9.25% | 0.0086% |
| Seagate Technology PLC | STX | 13,314.95 | 0.06% | 5.19% | 3.00% | 8.27% | 0.0049% |
| Constellation Brands Inc | STZ | 30,105.51 | 0.14% | 1.90% | 7.50% | 9.47% | 0.0128% |
| Stanley Black & Decker Inc | SWK | 20,234.17 | 0.09% | 2.47% | 8.00% | 10.57% | 0.0096% |
| Skyworks Solutions Inc | SWKS | 15,856.50 | 0.07% | 1.89% | 10.00% | 11.98% | 0.0085% |
| Synchrony Financial | SYF | 10,994.51 | 0.05% | 5.23% | 9.50% | 14.98% | 0.0074% |
| Stryker Corp | SYK | 66,055.39 | 0.30% | 1.30% | 12.00% | 13.38% | 0.0396% |
| Sysco Corp | SYY | 24,042.83 | 0.11% | 3.81% | 9.50% | 13.49% | 0.0145% |
| AT&T Inc | T | 216,838.60 | 0.97% | 6.99% | 5.50% | 12.68% | 0.1233% |
| Molson Coors Beverage Co | TAP | 9,867.61 | 0.04% | 5.00% | 5.00% | 10.13% | 0.0045% |
| TransDigm Group Inc | TDG | 17,604.38 | 0.08% | 0.00% | 15.50% | 15.50% | 0.0122% |
| TE Connectivity Ltd | TEL | 23,095.73 | 0.10% | 2.66% | 5.50% | 8.23% | 0.0085% |
| Truist Financial Corp | TFC | 43,888.82 | 0.20% | 5.63% | 11.50% | 17.45% | 0.0344% |
| Teleflex Inc | TFX | 14,887.87 | 0.07% | 0.42% | 14.00% | 14.45% | 0.0096% |
| Target Corp | TGT | 53,013.72 | 0.24% | 2.52% | 9.50% | 12.14% | 0.0289% |
| Tiffany & Co | TIF | 15,511.46 | 0.07% | 1.84% | 10.50% | 12.44% | 0.0087% |
| TJX Cos Inc/The | TJX | 59,088.37 | 0.27% | 2.12% | 13.50% | 15.76% | 0.0418% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Thermo Fisher Scientific Inc | TMO | 133,311.70 | 0.60% | 0.29% | 11.00% | 11.31% | 0.0676% |
| T-Mobile US Inc | TMUS | 74,422.20 | 0.33% | 0.00% | 14.00% | 14.00% | 0.0467% |
| Tapestry Inc | TPR | 4,131.72 | 0.02% | 0.00% | 10.50% | 10.50% | 0.0019% |
| T Rowe Price Group Inc | TROW | 24,763.41 | 0.11% | 3.41% | 10.00% | 13.58% | 0.0151% |
| Travelers Cos Inc/The | TRV | 26,812.17 | 0.12% | 3.13% | 7.50% | 10.75% | 0.0129% |
| Tractor Supply Co | TSCO | 10,717.57 | 0.05% | 1.72% | 9.50% | 11.30% | 0.0054% |
| Tyson Foods Inc | TSN | 21,319.65 | 0.10% | 2.95% | 7.00% | 10.05% | 0.0096% |
| Trane Technologies PLC | TT | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Take-Two Interactive Software Inc | TTWO | 13,499.99 | 0.06% | 0.00% | 20.50% | 20.50% | 0.0124% |
| Twitter Inc | TWTR | 21,720.19 | N/A | 0.00% | N/A | N/A | N/A |
| Texas Instruments Inc | TXN | 102,682.00 | 0.46% | 3.27% | 4.50% | 7.84% | 0.0361% |
| Textron Inc | TXT | 6,365.47 | 0.03% | 0.29% | 8.50% | 8.80% | 0.0025% |
| Under Armour Inc | UAA | 4,404.73 | 0.02% | 0.00% | 17.50% | 17.50% | 0.0035% |
| United Airlines Holdings Inc | UAL | 6,977.20 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0031% |
| UDR Inc | UDR | 10,652.61 | 0.05% | 3.54% | 5.00% | 8.63% | 0.0041% |
| Universal Health Services Inc | UHS | 9,370.40 | 0.04% | 0.75% | 11.00% | 11.79% | 0.0050% |
| Ulta Beauty Inc | ULTA | 11,489.25 | 0.05% | 0.00% | 13.00% | 13.00% | 0.0067% |
| UnitedHealth Group Inc | UNH | 253,902.90 | 1.14% | 1.61% | 12.00% | 13.71% | 0.1561% |
| Unum Group | UNM | 3,086.67 | 0.01% | 7.50% | 7.50% | 15.28% | 0.0021% |
| Union Pacific Corp | UNP | 103,552.10 | 0.46% | 2.59% | 11.50% | 14.24% | 0.0661% |
| United Parcel Service Inc | UPS | 84,722.30 | 0.38% | 4.09% | 7.00% | 11.23% | 0.0427% |
| United Rentals Inc | URI | 8,301.77 | 0.04% | 0.00% | 9.50% | 9.50% | 0.0035% |
| US Bancorp | USB | 54,692.63 | 0.25% | 4.83% | 5.00% | 9.95% | 0.0244% |
| Visa Inc | V | 343,757.10 | 1.54% | 0.72% | 18.00% | 18.78% | 0.2896% |
| Varian Medical Systems Inc | VAR | 10,451.36 | 0.05% | 0.00% | 13.50% | 13.50% | 0.0063% |
| VF Corp | VFC | 22,878.68 | 0.10% | 3.31% | 7.00% | 10.43% | 0.0107% |
| ViacomCBS Inc | VIAC | 5,923.13 | 0.03% | 6.08% | 12.00% | 18.44% | 0.0049% |
| Valero Energy Corp | VLO | 21,119.47 | 0.09% | 7.60% | 10.00% | 17.98% | 0.0170% |
| Vulcan Materials Co | VMC | 14,953.95 | 0.07% | 1.20% | 13.00% | 14.28% | 0.0096% |
| Vornado Realty Trust | VNO | 7,725.61 | 0.03% | 6.52% | -5.00% | 1.36% | 0.0005% |
| Verisk Analytics Inc | VRSK | 24,335.05 | 0.11% | 0.73% | 10.50% | 11.27% | 0.0123% |
| VeriSign Inc | VRSN | 22,549.34 | 0.10% | 0.00% | 11.00% | 11.00% | 0.0111% |
| Vertex Pharmaceuticals Inc | VRTX | 64,228.78 | 0.29% | 0.00% | 46.00% | 46.00% | 0.1325% |
| Ventas Inc | VTR | 10,750.65 | 0.05% | 10.51% | 1.50% | 12.09% | 0.0058% |
| Verizon Communications Inc | VZ | 239,048.30 | 1.07% | 4.27% | 4.50% | 8.87% | 0.0951% |
| Westinghouse Air Brake Technologies Corp | WAB | 10,069.95 | 0.05% | 0.91% | 12.50% | 13.47% | 0.0061% |
| Waters Corp | WAT | 12,768.14 | 0.06% | 0.00% | 10.50% | 10.50% | 0.0060% |
| Walgreens Boots Alliance Inc | WBA | 38,267.80 | 0.17% | 4.25% | 6.50% | 10.89% | 0.0187% |
| Western Digital Corp | WDC | 13,556.66 | 0.06% | 4.41% | 0.50% | 4.92% | 0.0030% |
| WEC Energy Group Inc | WEC | 29,083.01 | 0.13% | 2.79% | 6.00% | 8.87% | 0.0116% |
| Welltower Inc | WELL | 19,794.05 | 0.09% | 6.75% | 9.50% | 16.57% | 0.0147% |
| Wells Fargo & Co | WFC | 129,269.60 | 0.58% | 6.87% | 5.50% | 12.56% | 0.0728% |
| Whirlpool Corp | WHR | 6,279.84 | 0.03% | 4.82% | 5.00% | 9.94% | 0.0028% |
| Willis Towers Watson PLC | WLTW | 24,457.53 | 0.11% | 1.43% | 17.50% | 19.06% | 0.0209% |
| Waste Management Inc | WM | 40,558.18 | 0.18% | 2.28% | 7.00% | 9.36% | 0.0170% |
| Williams Cos Inc/The | WMB | 18,592.08 | 0.08% | 10.43% | 13.00% | 24.11% | 0.0201% |
| Walmart Inc | WMT | 345,903.80 | 1.55% | 1.77% | 7.50% | 9.34% | 0.1448% |
| WR Berkley Corp | WRB | 10,128.01 | 0.05% | 0.80% | 10.00% | 10.84% | 0.0049% |
| Westrock Co | WRK | 7,930.30 | 0.04% | 6.13% | 6.50% | 12.83% | 0.0046% |
| Western Union Co/The | WU | 8,468.68 | 0.04% | 4.44% | 6.50% | 11.08% | 0.0042% |
| Weyerhaeuser Co | WY | 14,499.08 | 0.07% | 6.99% | 10.50% | 17.86% | 0.0116% |
| Wynn Resorts Ltd | WYNN | 7,415.63 | 0.03% | 5.79% | 14.50% | 20.71% | 0.0069% |
| Xcel Energy Inc | XEL | 32,941.05 | 0.15% | 2.74% | 5.50% | 8.32% | 0.0123% |
| Xilinx Inc | XLNX | 21,026.73 | 0.09% | 1.75% | 6.00% | 7.80% | 0.0074% |
| Exxon Mobil Corp | XOM | 185,660.90 | 0.83% | 8.07% | 9.00% | 17.43% | 0.1452% |
| DENTSPLY SIRONA Inc | XRAY | 8,798.63 | 0.04% | 1.01% | 6.00% | 7.04% | 0.0028% |
| Xerox Holdings Corp | XRX | 4,098.32 | 0.02% | 5.19% | 9.50% | 14.94% | 0.0027% |
| Xylem Inc/NY | XYL | 12,445.87 | 0.06% | 1.51% | 8.50% | 10.07% | 0.0056% |
| Yum! Brands Inc | YUM | 22,837.11 | 0.10% | 2.49% | 11.00% | 13.63% | 0.0140% |
| Zimmer Biomet Holdings Inc | ZBH | 22,879.17 | 0.10% | 0.86% | 4.50% | 5.38% | 0.0055% |
| Zebra Technologies Corp | ZBRA | 10,628.34 | 0.05% | 0.00% | 15.00% | 15.00% | 0.0071% |
| Zions Bancorp NA | ZION | 4,859.28 | 0.02% | 4.62% | 9.50% | 14.34% | 0.0031% |
| Zoetis Inc | ZTS | 60,510.94 | 0.27% | 0.63% | 12.00% | 12.67% | 0.0344% |
| Total Market Capitalization: | | 22,297,457.29 | | | | | 14.82% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg and Value Line Beta Coefficients

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.939 | 0.60 |
| Alliant Energy Corporation | LNT | 1.003 | 0.55 |
| Ameren Corporation | AEE | 0.922 | 0.50 |
| American Electric Power Company, Inc. | AEP | 0.983 | 0.50 |
| Avangrid, Inc. | AGR | 0.755 | 0.40 |
| Avista | AVA | 0.927 | 0.60 |
| CMS Energy Corporation | CMS | 0.940 | 0.50 |
| DTE Energy Company | DTE | 1.097 | 0.50 |
| Evergy, Inc | EVRG | 1.043 | 0.66 |
| Hawaiian Electric Industries, Inc. | HE | 0.768 | 0.55 |
| NextEra Energy, Inc. | NEE | 0.912 | 0.50 |
| NorthWestern Corporation | NWE | 1.184 | 0.60 |
| OGE Energy Corp. | OGE | 1.163 | 0.70 |
| Otter Tail Corporation | OTTR | 0.973 | 0.70 |
| Pinnacle West Capital Corporation | PNW | 1.051 | 0.50 |
| PNM Resources, Inc. | PNM | 1.269 | 0.60 |
| Portland General Electric Company | POR | 0.986 | 0.55 |
| Southern Company | SO | 1.050 | 0.50 |
| WEC Energy Group, Inc. | WEC | 0.978 | 0.50 |
| Xcel Energy Inc. | XEL | 0.958 | 0.45 |
| Mean | | 0.995 | 0.548 |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

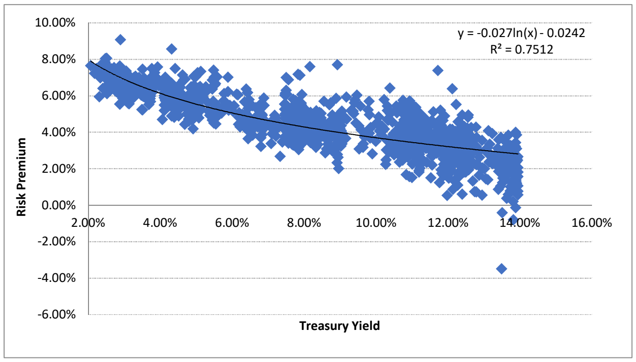
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|
| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM Result | |
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg MRP | Value Line MRP | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury [9] | 1.37% | 0.995 | 11.56% | 13.45% | 12.87% | 14.75% | 12.89% | 14.77% |
| Near-Term Projected 30-Year Treasury [10] | 1.75% | 0.995 | 11.56% | 13.45% | 13.25% | 15.13% | 13.27% | 15.15% |
| Long-Term Projected 30-Year Treasury [11] | 3.45% | 0.995 | 11.56% | 13.45% | 14.95% | 16.83% | 14.97% | 16.85% |
| Mean | | | | | 13.06% | 14.94% | 13.08% | 14.96% |

| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM Result | |
|---|---|---|---|---|---|---|---|---|
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg MRP | Value Line MRP | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP AVERAGE VALUE LINE AVERAGE BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury [9] | 1.37% | 0.548 | 11.56% | 13.45% | 7.70% | 8.74% | 9.01% | 10.26% |
| Near-Term Projected 30-Year Treasury [10] | 1.75% | 0.548 | 11.56% | 13.45% | 8.08% | 9.11% | 9.39% | 10.64% |
| Long-Term Projected 30-Year Treasury [11] | 3.45% | 0.548 | 11.56% | 13.45% | 9.78% | 10.81% | 11.09% | 12.34% |
| Mean | | | | | 7.89% | 8.93% | 9.20% | 10.45% |

Notes:
[1] *See Notes [9], [10], [11]*
[2] Source: Rebuttal Exhibit DWD-3
[3] Source: Rebuttal Exhibit DWD-2
[4] Source: Rebuttal Exhibit DWD-2
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Equals Col. [1] + 0.25 x Col. [3] + 0.75 x Col. [2] x Col. [3]
[8] Equals Col. [1] + 0.25 x Col. [4] + 0.75 x Col. [2] x Col. [4]
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 39, No. 4, April 1, 2020, at 2.
[11] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14.

Bond Yield Plus Risk Premium

| | [1] | [2] | [3] | [4] | [5] |
|---|---|---|---|---|---|
| | Constant | Slope | 30-Year Treasury Yield | Risk Premium | Return on Equity |
| | -2.42% | -2.66% | | | |
| Current 30-Year Treasury | | | 1.37% | 8.98% | 10.35% |
| Near-Term Projected 30-Year Treasury | | | 1.75% | 8.33% | 10.08% |
| Long-Term Projected 30-Year Treasury | | | 3.45% | 6.52% | 9.97% |




Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 39, No. 4, April 1, 2020, at 2.
Long Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Global Market Intelligence
[7] Source: S&P Global Market Intelligence
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

| [6] Date of Electric Rate Case | [7] Return on Equity | [8] 30-Year Treasury Yield | [9] Risk Premium |
|---|---|---|---|
| 1/1/1980 | 14.50% | 9.36% | 5.14% |
| 1/7/1980 | 14.39% | 9.39% | 5.00% |
| 1/9/1980 | 15.00% | 9.40% | 5.60% |
| 1/14/1980 | 15.17% | 9.42% | 5.75% |
| 1/17/1980 | 13.93% | 9.44% | 4.49% |
| 1/23/1980 | 15.50% | 9.47% | 6.03% |
| 1/30/1980 | 13.86% | 9.52% | 4.34% |
| 1/31/1980 | 12.61% | 9.53% | 3.08% |
| 2/6/1980 | 13.71% | 9.58% | 4.13% |
| 2/13/1980 | 12.80% | 9.64% | 3.16% |
| 2/14/1980 | 13.00% | 9.65% | 3.35% |
| 2/19/1980 | 13.50% | 9.68% | 3.82% |
| 2/27/1980 | 13.75% | 9.78% | 3.97% |
| 2/29/1980 | 13.75% | 9.81% | 3.94% |
| 2/29/1980 | 14.00% | 9.81% | 4.19% |
| 2/29/1980 | 14.77% | 9.81% | 4.96% |
| 3/7/1980 | 12.70% | 9.90% | 2.80% |
| 3/14/1980 | 13.50% | 9.97% | 3.53% |
| 3/26/1980 | 14.16% | 10.11% | 4.05% |
| 3/27/1980 | 14.24% | 10.12% | 4.12% |
| 3/28/1980 | 14.50% | 10.14% | 4.36% |
| 4/11/1980 | 12.75% | 10.28% | 2.47% |
| 4/14/1980 | 13.85% | 10.29% | 3.56% |
| 4/16/1980 | 15.50% | 10.32% | 5.18% |
| 4/22/1980 | 13.25% | 10.36% | 2.89% |
| 4/22/1980 | 13.90% | 10.36% | 3.54% |
| 4/24/1980 | 16.80% | 10.38% | 6.42% |
| 4/29/1980 | 15.50% | 10.41% | 5.09% |
| 5/6/1980 | 13.70% | 10.45% | 3.25% |
| 5/7/1980 | 15.00% | 10.46% | 4.54% |
| 5/8/1980 | 13.75% | 10.47% | 3.28% |
| 5/9/1980 | 14.35% | 10.47% | 3.88% |
| 5/13/1980 | 13.60% | 10.49% | 3.11% |
| 5/15/1980 | 13.25% | 10.50% | 2.75% |
| 5/19/1980 | 13.75% | 10.52% | 3.23% |
| 5/27/1980 | 13.62% | 10.55% | 3.07% |
| 5/27/1980 | 14.60% | 10.55% | 4.05% |
| 5/29/1980 | 16.00% | 10.56% | 5.44% |
| 5/30/1980 | 13.80% | 10.57% | 3.23% |
| 6/2/1980 | 15.63% | 10.58% | 5.05% |
| 6/9/1980 | 15.90% | 10.61% | 5.29% |
| 6/10/1980 | 13.78% | 10.61% | 3.17% |
| 6/12/1980 | 14.25% | 10.62% | 3.63% |
| 6/19/1980 | 13.40% | 10.63% | 2.77% |
| 6/30/1980 | 13.00% | 10.65% | 2.35% |
| 6/30/1980 | 13.40% | 10.65% | 2.75% |
| 7/9/1980 | 14.75% | 10.68% | 4.07% |
| 7/10/1980 | 15.00% | 10.69% | 4.31% |
| 7/15/1980 | 15.80% | 10.70% | 5.10% |
| 7/18/1980 | 13.80% | 10.72% | 3.08% |
| 7/22/1980 | 14.10% | 10.73% | 3.37% |
| 7/24/1980 | 15.00% | 10.73% | 4.27% |
| 7/25/1980 | 13.48% | 10.74% | 2.74% |
| 7/31/1980 | 14.58% | 10.76% | 3.82% |
| 8/8/1980 | 13.50% | 10.78% | 2.72% |
| 8/8/1980 | 14.00% | 10.78% | 3.22% |
| 8/8/1980 | 15.45% | 10.78% | 4.67% |
| 8/11/1980 | 14.85% | 10.78% | 4.07% |
| 8/14/1980 | 14.00% | 10.79% | 3.21% |
| 8/14/1980 | 16.25% | 10.79% | 5.46% |
| 8/25/1980 | 13.75% | 10.82% | 2.93% |
| 8/27/1980 | 13.80% | 10.83% | 2.97% |
| 8/29/1980 | 12.50% | 10.84% | 1.66% |
| 9/15/1980 | 13.50% | 10.88% | 2.62% |
| 9/15/1980 | 13.93% | 10.88% | 3.05% |
| 9/15/1980 | 15.80% | 10.88% | 4.92% |
| 9/24/1980 | 12.50% | 10.93% | 1.57% |
| 9/24/1980 | 15.00% | 10.93% | 4.07% |
| 9/26/1980 | 13.75% | 10.95% | 2.80% |
| 9/30/1980 | 14.10% | 10.96% | 3.14% |
| 9/30/1980 | 14.20% | 10.96% | 3.24% |
| 10/1/1980 | 13.90% | 10.97% | 2.93% |
| 10/3/1980 | 15.50% | 10.99% | 4.51% |
| 10/7/1980 | 12.50% | 11.00% | 1.50% |
| 10/9/1980 | 13.25% | 11.01% | 2.24% |
| 10/9/1980 | 14.50% | 11.01% | 3.49% |
| 10/9/1980 | 14.50% | 11.01% | 3.49% |
| 10/16/1980 | 16.10% | 11.03% | 5.07% |
| 10/17/1980 | 14.50% | 11.03% | 3.47% |
| 10/31/1980 | 13.75% | 11.11% | 2.64% |
| 10/31/1980 | 14.25% | 11.11% | 3.14% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 11/4/1980 | 15.00% | 11.12% | 3.88% |
| 11/5/1980 | 13.75% | 11.13% | 2.62% |
| 11/5/1980 | 14.00% | 11.13% | 2.87% |
| 11/8/1980 | 13.75% | 11.15% | 2.60% |
| 11/10/1980 | 14.85% | 11.15% | 3.70% |
| 11/17/1980 | 14.00% | 11.18% | 2.82% |
| 11/18/1980 | 14.00% | 11.19% | 2.81% |
| 11/19/1980 | 13.00% | 11.19% | 1.81% |
| 11/24/1980 | 14.00% | 11.20% | 2.80% |
| 11/26/1980 | 14.00% | 11.21% | 2.79% |
| 12/8/1980 | 14.15% | 11.22% | 2.93% |
| 12/8/1980 | 15.10% | 11.22% | 3.88% |
| 12/9/1980 | 15.35% | 11.22% | 4.13% |
| 12/12/1980 | 15.45% | 11.22% | 4.23% |
| 12/17/1980 | 13.25% | 11.23% | 2.02% |
| 12/18/1980 | 15.80% | 11.23% | 4.57% |
| 12/19/1980 | 14.50% | 11.23% | 3.27% |
| 12/19/1980 | 14.64% | 11.23% | 3.41% |
| 12/22/1980 | 13.45% | 11.22% | 2.23% |
| 12/22/1980 | 15.00% | 11.22% | 3.78% |
| 12/30/1980 | 14.50% | 11.21% | 3.29% |
| 12/30/1980 | 14.95% | 11.21% | 3.74% |
| 12/31/1980 | 13.39% | 11.21% | 2.18% |
| 1/2/1981 | 15.25% | 11.21% | 4.04% |
| 1/7/1981 | 14.30% | 11.21% | 3.09% |
| 1/19/1981 | 15.25% | 11.19% | 4.06% |
| 1/23/1981 | 13.10% | 11.20% | 1.90% |
| 1/23/1981 | 14.40% | 11.20% | 3.20% |
| 1/26/1981 | 15.25% | 11.20% | 4.05% |
| 1/27/1981 | 15.00% | 11.20% | 3.80% |
| 1/31/1981 | 13.47% | 11.21% | 2.26% |
| 2/3/1981 | 15.25% | 11.23% | 4.02% |
| 2/5/1981 | 15.75% | 11.25% | 4.50% |
| 2/11/1981 | 15.60% | 11.28% | 4.32% |
| 2/20/1981 | 15.25% | 11.34% | 3.91% |
| 3/11/1981 | 15.40% | 11.50% | 3.90% |
| 3/12/1981 | 14.51% | 11.51% | 3.00% |
| 3/12/1981 | 16.00% | 11.51% | 4.49% |
| 3/13/1981 | 13.02% | 11.52% | 1.50% |
| 3/18/1981 | 16.19% | 11.55% | 4.64% |
| 3/19/1981 | 13.75% | 11.56% | 2.19% |
| 3/23/1981 | 14.30% | 11.58% | 2.72% |
| 3/25/1981 | 15.30% | 11.61% | 3.69% |
| 4/1/1981 | 14.53% | 11.69% | 2.84% |
| 4/3/1981 | 19.10% | 11.72% | 7.38% |
| 4/9/1981 | 15.00% | 11.79% | 3.21% |
| 4/9/1981 | 15.30% | 11.79% | 3.51% |
| 4/9/1981 | 16.50% | 11.79% | 4.71% |
| 4/9/1981 | 17.00% | 11.79% | 5.21% |
| 4/10/1981 | 13.75% | 11.81% | 1.94% |
| 4/13/1981 | 13.57% | 11.83% | 1.74% |
| 4/15/1981 | 15.30% | 11.86% | 3.44% |
| 4/16/1981 | 13.50% | 11.88% | 1.62% |
| 4/17/1981 | 14.10% | 11.88% | 2.22% |
| 4/21/1981 | 14.00% | 11.91% | 2.09% |
| 4/21/1981 | 16.80% | 11.91% | 4.89% |
| 4/24/1981 | 16.00% | 11.96% | 4.04% |
| 4/27/1981 | 12.50% | 11.98% | 0.52% |
| 4/27/1981 | 13.61% | 11.98% | 1.63% |
| 4/29/1981 | 13.65% | 12.01% | 1.64% |
| 4/30/1981 | 13.50% | 12.02% | 1.48% |
| 5/4/1981 | 16.22% | 12.06% | 4.16% |
| 5/5/1981 | 14.40% | 12.08% | 2.32% |
| 5/7/1981 | 16.25% | 12.12% | 4.13% |
| 5/7/1981 | 16.27% | 12.12% | 4.15% |
| 5/8/1981 | 13.00% | 12.14% | 0.86% |
| 5/8/1981 | 16.00% | 12.14% | 3.86% |
| 5/12/1981 | 13.50% | 12.17% | 1.33% |
| 5/15/1981 | 15.75% | 12.23% | 3.52% |
| 5/18/1981 | 14.88% | 12.24% | 2.64% |
| 5/20/1981 | 16.00% | 12.27% | 3.73% |
| 5/21/1981 | 14.00% | 12.28% | 1.72% |
| 5/26/1981 | 14.90% | 12.31% | 2.59% |
| 5/27/1981 | 15.00% | 12.32% | 2.68% |
| 5/29/1981 | 15.50% | 12.34% | 3.16% |
| 6/1/1981 | 16.50% | 12.35% | 4.15% |
| 6/3/1981 | 14.67% | 12.38% | 2.29% |
| 6/5/1981 | 13.00% | 12.40% | 0.60% |
| 6/10/1981 | 16.75% | 12.42% | 4.33% |
| 6/17/1981 | 14.40% | 12.46% | 1.94% |
| 6/18/1981 | 16.33% | 12.47% | 3.86% |
| 6/25/1981 | 14.75% | 12.52% | 2.23% |
| 6/26/1981 | 16.00% | 12.53% | 3.47% |
| 6/30/1981 | 15.25% | 12.55% | 2.70% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 7/1/1981 | 15.50% | 12.56% | 2.94% |
| 7/1/1981 | 17.50% | 12.56% | 4.94% |
| 7/10/1981 | 16.00% | 12.62% | 3.38% |
| 7/14/1981 | 16.90% | 12.64% | 4.26% |
| 7/15/1981 | 16.00% | 12.65% | 3.35% |
| 7/17/1981 | 15.00% | 12.67% | 2.33% |
| 7/20/1981 | 15.00% | 12.68% | 2.32% |
| 7/21/1981 | 14.00% | 12.69% | 1.31% |
| 7/28/1981 | 13.48% | 12.75% | 0.73% |
| 7/31/1981 | 13.50% | 12.79% | 0.71% |
| 7/31/1981 | 15.00% | 12.79% | 2.21% |
| 7/31/1981 | 16.00% | 12.79% | 3.21% |
| 8/5/1981 | 15.71% | 12.83% | 2.88% |
| 8/10/1981 | 14.50% | 12.87% | 1.63% |
| 8/11/1981 | 15.00% | 12.88% | 2.12% |
| 8/20/1981 | 13.50% | 12.95% | 0.55% |
| 8/20/1981 | 16.50% | 12.95% | 3.55% |
| 8/24/1981 | 15.00% | 12.97% | 2.03% |
| 8/28/1981 | 15.00% | 13.01% | 1.99% |
| 9/3/1981 | 14.50% | 13.06% | 1.44% |
| 9/10/1981 | 14.50% | 13.11% | 1.39% |
| 9/11/1981 | 16.00% | 13.12% | 2.88% |
| 9/16/1981 | 16.00% | 13.15% | 2.85% |
| 9/17/1981 | 16.50% | 13.16% | 3.34% |
| 9/23/1981 | 15.85% | 13.20% | 2.65% |
| 9/28/1981 | 15.50% | 13.23% | 2.27% |
| 10/9/1981 | 15.75% | 13.34% | 2.41% |
| 10/15/1981 | 16.25% | 13.37% | 2.88% |
| 10/16/1981 | 15.50% | 13.39% | 2.11% |
| 10/16/1981 | 16.50% | 13.39% | 3.11% |
| 10/19/1981 | 14.25% | 13.40% | 0.85% |
| 10/20/1981 | 15.25% | 13.41% | 1.84% |
| 10/20/1981 | 17.00% | 13.41% | 3.59% |
| 10/23/1981 | 16.00% | 13.46% | 2.54% |
| 10/27/1981 | 10.00% | 13.49% | -3.49% |
| 10/29/1981 | 14.75% | 13.52% | 1.23% |
| 10/29/1981 | 16.50% | 13.52% | 2.98% |
| 11/3/1981 | 15.17% | 13.54% | 1.63% |
| 11/5/1981 | 16.60% | 13.56% | 3.04% |
| 11/6/1981 | 15.17% | 13.57% | 1.60% |
| 11/24/1981 | 15.50% | 13.61% | 1.89% |
| 11/25/1981 | 15.25% | 13.61% | 1.64% |
| 11/25/1981 | 15.35% | 13.61% | 1.74% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 12/1/1981 | 15.70% | 13.61% | 2.09% |
| 12/1/1981 | 16.00% | 13.61% | 2.39% |
| 12/1/1981 | 16.49% | 13.61% | 2.88% |
| 12/1/1981 | 16.50% | 13.61% | 2.89% |
| 12/4/1981 | 16.00% | 13.61% | 2.39% |
| 12/11/1981 | 16.25% | 13.63% | 2.62% |
| 12/14/1981 | 14.00% | 13.63% | 0.37% |
| 12/15/1981 | 15.81% | 13.63% | 2.18% |
| 12/15/1981 | 16.00% | 13.63% | 2.37% |
| 12/16/1981 | 15.25% | 13.63% | 1.62% |
| 12/17/1981 | 16.50% | 13.64% | 2.86% |
| 12/18/1981 | 15.45% | 13.64% | 1.81% |
| 12/30/1981 | 14.25% | 13.67% | 0.58% |
| 12/30/1981 | 16.00% | 13.67% | 2.33% |
| 12/30/1981 | 16.25% | 13.67% | 2.58% |
| 12/31/1981 | 16.15% | 13.68% | 2.47% |
| 1/4/1982 | 15.50% | 13.68% | 1.82% |
| 1/11/1982 | 14.50% | 13.73% | 0.77% |
| 1/11/1982 | 17.00% | 13.73% | 3.27% |
| 1/13/1982 | 14.75% | 13.74% | 1.01% |
| 1/14/1982 | 15.75% | 13.75% | 2.00% |
| 1/15/1982 | 15.00% | 13.76% | 1.24% |
| 1/15/1982 | 16.50% | 13.76% | 2.74% |
| 1/22/1982 | 16.25% | 13.80% | 2.45% |
| 1/27/1982 | 16.84% | 13.81% | 3.03% |
| 1/28/1982 | 13.00% | 13.82% | -0.82% |
| 1/29/1982 | 15.50% | 13.82% | 1.68% |
| 2/1/1982 | 15.85% | 13.83% | 2.02% |
| 2/3/1982 | 16.44% | 13.84% | 2.60% |
| 2/8/1982 | 15.50% | 13.86% | 1.64% |
| 2/11/1982 | 16.00% | 13.88% | 2.12% |
| 2/11/1982 | 16.20% | 13.88% | 2.32% |
| 2/17/1982 | 15.00% | 13.89% | 1.11% |
| 2/19/1982 | 15.17% | 13.89% | 1.28% |
| 2/26/1982 | 15.25% | 13.89% | 1.36% |
| 3/1/1982 | 15.03% | 13.89% | 1.14% |
| 3/1/1982 | 16.00% | 13.89% | 2.11% |
| 3/3/1982 | 15.00% | 13.88% | 1.12% |
| 3/8/1982 | 17.10% | 13.88% | 3.22% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/12/1982 | 16.25% | 13.88% | 2.37% |
| 3/17/1982 | 17.30% | 13.88% | 3.42% |
| 3/22/1982 | 15.10% | 13.89% | 1.21% |
| 3/27/1982 | 15.40% | 13.90% | 1.50% |
| 3/30/1982 | 15.50% | 13.91% | 1.59% |
| 3/31/1982 | 17.00% | 13.91% | 3.09% |
| 4/1/1982 | 14.70% | 13.92% | 0.78% |
| 4/1/1982 | 16.50% | 13.92% | 2.58% |
| 4/2/1982 | 15.50% | 13.92% | 1.58% |
| 4/5/1982 | 15.50% | 13.93% | 1.57% |
| 4/8/1982 | 16.40% | 13.94% | 2.46% |
| 4/13/1982 | 14.50% | 13.94% | 0.56% |
| 4/23/1982 | 15.75% | 13.94% | 1.81% |
| 4/27/1982 | 15.00% | 13.94% | 1.06% |
| 4/28/1982 | 15.75% | 13.94% | 1.81% |
| 4/30/1982 | 14.70% | 13.94% | 0.76% |
| 4/30/1982 | 15.50% | 13.94% | 1.56% |
| 5/3/1982 | 16.60% | 13.94% | 2.66% |
| 5/4/1982 | 16.00% | 13.94% | 2.06% |
| 5/14/1982 | 15.50% | 13.92% | 1.58% |
| 5/18/1982 | 15.42% | 13.92% | 1.50% |
| 5/19/1982 | 14.69% | 13.92% | 0.77% |
| 5/20/1982 | 15.00% | 13.91% | 1.09% |
| 5/20/1982 | 15.10% | 13.91% | 1.19% |
| 5/20/1982 | 15.50% | 13.91% | 1.59% |
| 5/20/1982 | 16.30% | 13.91% | 2.39% |
| 5/21/1982 | 17.75% | 13.91% | 3.84% |
| 5/27/1982 | 15.00% | 13.89% | 1.11% |
| 5/28/1982 | 15.50% | 13.89% | 1.61% |
| 5/28/1982 | 17.00% | 13.89% | 3.11% |
| 6/1/1982 | 13.75% | 13.89% | -0.14% |
| 6/1/1982 | 16.60% | 13.89% | 2.71% |
| 6/9/1982 | 17.86% | 13.88% | 3.98% |
| 6/14/1982 | 15.75% | 13.88% | 1.87% |
| 6/15/1982 | 14.85% | 13.87% | 0.98% |
| 6/18/1982 | 15.50% | 13.86% | 1.64% |
| 6/21/1982 | 14.90% | 13.86% | 1.04% |
| 6/23/1982 | 16.00% | 13.86% | 2.14% |
| 6/23/1982 | 16.17% | 13.86% | 2.31% |
| 6/24/1982 | 14.85% | 13.86% | 0.99% |
| 6/25/1982 | 14.70% | 13.85% | 0.85% |
| 7/1/1982 | 16.00% | 13.84% | 2.16% |
| 7/2/1982 | 15.62% | 13.83% | 1.79% |
| 7/2/1982 | 17.00% | 13.83% | 3.17% |
| 7/13/1982 | 14.00% | 13.82% | 0.18% |
| 7/13/1982 | 16.80% | 13.82% | 2.98% |
| 7/14/1982 | 15.76% | 13.81% | 1.95% |
| 7/14/1982 | 16.02% | 13.81% | 2.21% |
| 7/19/1982 | 16.50% | 13.79% | 2.71% |
| 7/22/1982 | 14.50% | 13.76% | 0.74% |
| 7/22/1982 | 17.00% | 13.76% | 3.24% |
| 7/27/1982 | 16.75% | 13.74% | 3.01% |
| 7/29/1982 | 16.50% | 13.73% | 2.77% |
| 8/11/1982 | 17.50% | 13.68% | 3.82% |
| 8/18/1982 | 17.07% | 13.62% | 3.45% |
| 8/20/1982 | 15.73% | 13.60% | 2.13% |
| 8/25/1982 | 16.00% | 13.57% | 2.43% |
| 8/26/1982 | 15.50% | 13.56% | 1.94% |
| 8/30/1982 | 15.00% | 13.55% | 1.45% |
| 9/3/1982 | 16.20% | 13.53% | 2.67% |
| 9/8/1982 | 15.00% | 13.52% | 1.48% |
| 9/15/1982 | 13.08% | 13.51% | -0.43% |
| 9/15/1982 | 16.25% | 13.51% | 2.74% |
| 9/16/1982 | 16.00% | 13.50% | 2.50% |
| 9/17/1982 | 15.25% | 13.50% | 1.75% |
| 9/23/1982 | 17.17% | 13.47% | 3.70% |
| 9/24/1982 | 14.50% | 13.47% | 1.03% |
| 9/27/1982 | 15.25% | 13.46% | 1.79% |
| 10/1/1982 | 15.50% | 13.42% | 2.08% |
| 10/15/1982 | 15.90% | 13.32% | 2.58% |
| 10/22/1982 | 15.75% | 13.24% | 2.51% |
| 10/22/1982 | 17.15% | 13.24% | 3.91% |
| 10/29/1982 | 15.54% | 13.16% | 2.38% |
| 11/1/1982 | 15.50% | 13.14% | 2.36% |
| 11/3/1982 | 17.20% | 13.12% | 4.08% |
| 11/4/1982 | 16.25% | 13.10% | 3.15% |
| 11/5/1982 | 16.20% | 13.09% | 3.11% |
| 11/9/1982 | 16.00% | 13.05% | 2.95% |
| 11/23/1982 | 15.50% | 12.88% | 2.62% |
| 11/23/1982 | 15.85% | 12.88% | 2.97% |
| 11/30/1982 | 16.50% | 12.80% | 3.70% |
| 12/1/1982 | 17.04% | 12.78% | 4.26% |
| 12/6/1982 | 15.00% | 12.72% | 2.28% |
| 12/6/1982 | 16.35% | 12.72% | 3.63% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/10/1982 | 15.50% | 12.66% | 2.84% |
| 12/13/1982 | 16.00% | 12.64% | 3.36% |
| 12/14/1982 | 15.30% | 12.62% | 2.68% |
| 12/14/1982 | 16.40% | 12.62% | 3.78% |
| 12/20/1982 | 16.00% | 12.57% | 3.43% |
| 12/21/1982 | 14.75% | 12.55% | 2.20% |
| 12/21/1982 | 15.85% | 12.55% | 3.30% |
| 12/22/1982 | 16.25% | 12.54% | 3.71% |
| 12/22/1982 | 16.58% | 12.54% | 4.04% |
| 12/22/1982 | 16.75% | 12.54% | 4.21% |
| 12/29/1982 | 14.90% | 12.48% | 2.42% |
| 12/29/1982 | 16.25% | 12.48% | 3.77% |
| 12/30/1982 | 16.00% | 12.46% | 3.54% |
| 12/30/1982 | 16.35% | 12.46% | 3.89% |
| 12/30/1982 | 16.77% | 12.46% | 4.31% |
| 1/5/1983 | 17.33% | 12.40% | 4.93% |
| 1/11/1983 | 15.90% | 12.34% | 3.56% |
| 1/12/1983 | 14.63% | 12.32% | 2.31% |
| 1/12/1983 | 15.50% | 12.32% | 3.18% |
| 1/20/1983 | 17.75% | 12.23% | 5.52% |
| 1/21/1983 | 15.00% | 12.21% | 2.79% |
| 1/24/1983 | 14.50% | 12.20% | 2.30% |
| 1/24/1983 | 15.50% | 12.20% | 3.30% |
| 1/25/1983 | 15.85% | 12.19% | 3.66% |
| 1/27/1983 | 16.14% | 12.16% | 3.98% |
| 2/1/1983 | 18.50% | 12.13% | 6.37% |
| 2/4/1983 | 14.00% | 12.09% | 1.91% |
| 2/10/1983 | 15.00% | 12.05% | 2.95% |
| 2/21/1983 | 15.50% | 11.98% | 3.52% |
| 2/22/1983 | 15.50% | 11.96% | 3.54% |
| 2/23/1983 | 15.10% | 11.95% | 3.15% |
| 2/23/1983 | 16.00% | 11.95% | 4.05% |
| 3/2/1983 | 15.25% | 11.89% | 3.36% |
| 3/9/1983 | 15.20% | 11.82% | 3.38% |
| 3/15/1983 | 13.00% | 11.76% | 1.24% |
| 3/18/1983 | 15.25% | 11.72% | 3.53% |
| 3/23/1983 | 15.40% | 11.68% | 3.72% |
| 3/24/1983 | 15.00% | 11.66% | 3.34% |
| 3/29/1983 | 15.50% | 11.62% | 3.88% |
| 3/30/1983 | 16.71% | 11.60% | 5.11% |
| 3/31/1983 | 15.00% | 11.58% | 3.42% |
| 4/4/1983 | 15.20% | 11.57% | 3.63% |
| 4/8/1983 | 15.50% | 11.49% | 4.01% |
| 4/11/1983 | 14.81% | 11.48% | 3.33% |
| 4/19/1983 | 14.50% | 11.36% | 3.14% |
| 4/20/1983 | 16.00% | 11.35% | 4.65% |
| 4/29/1983 | 16.00% | 11.23% | 4.77% |
| 5/1/1983 | 14.50% | 11.23% | 3.27% |
| 5/9/1983 | 15.50% | 11.14% | 4.36% |
| 5/11/1983 | 16.46% | 11.11% | 5.35% |
| 5/12/1983 | 14.14% | 11.10% | 3.04% |
| 5/18/1983 | 15.00% | 11.04% | 3.96% |
| 5/23/1983 | 14.90% | 11.00% | 3.90% |
| 5/23/1983 | 15.50% | 11.00% | 4.50% |
| 5/25/1983 | 15.50% | 10.97% | 4.53% |
| 5/27/1983 | 15.00% | 10.95% | 4.05% |
| 5/31/1983 | 14.00% | 10.94% | 3.06% |
| 5/31/1983 | 15.50% | 10.94% | 4.56% |
| 6/2/1983 | 14.50% | 10.92% | 3.58% |
| 6/17/1983 | 15.03% | 10.83% | 4.20% |
| 7/1/1983 | 14.80% | 10.77% | 4.03% |
| 7/1/1983 | 14.90% | 10.77% | 4.13% |
| 7/8/1983 | 16.25% | 10.75% | 5.50% |
| 7/13/1983 | 13.20% | 10.75% | 2.45% |
| 7/19/1983 | 15.00% | 10.74% | 4.26% |
| 7/19/1983 | 15.10% | 10.74% | 4.36% |
| 7/25/1983 | 16.25% | 10.73% | 5.52% |
| 7/28/1983 | 15.90% | 10.74% | 5.16% |
| 8/3/1983 | 16.34% | 10.75% | 5.59% |
| 8/3/1983 | 16.50% | 10.75% | 5.75% |
| 8/19/1983 | 15.00% | 10.80% | 4.20% |
| 8/22/1983 | 15.50% | 10.80% | 4.70% |
| 8/22/1983 | 16.40% | 10.80% | 5.60% |
| 8/31/1983 | 14.75% | 10.85% | 3.90% |
| 9/7/1983 | 15.00% | 10.87% | 4.13% |
| 9/14/1983 | 15.78% | 10.89% | 4.89% |
| 9/16/1983 | 15.00% | 10.90% | 4.10% |
| 9/19/1983 | 14.50% | 10.91% | 3.59% |
| 9/20/1983 | 16.50% | 10.91% | 5.59% |
| 9/28/1983 | 14.50% | 10.94% | 3.56% |
| 9/29/1983 | 15.50% | 10.95% | 4.55% |
| 9/30/1983 | 15.25% | 10.95% | 4.30% |
| 9/30/1983 | 16.15% | 10.95% | 5.20% |
| 10/4/1983 | 14.80% | 10.96% | 3.84% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/7/1983 | 16.00% | 10.97% | 5.03% |
| 10/13/1983 | 15.52% | 10.99% | 4.53% |
| 10/17/1983 | 15.50% | 11.00% | 4.50% |
| 10/18/1983 | 14.50% | 11.00% | 3.50% |
| 10/19/1983 | 16.25% | 11.01% | 5.24% |
| 10/19/1983 | 16.50% | 11.01% | 5.49% |
| 10/26/1983 | 15.00% | 11.04% | 3.96% |
| 10/27/1983 | 15.20% | 11.04% | 4.16% |
| 11/1/1983 | 16.00% | 11.06% | 4.94% |
| 11/9/1983 | 14.90% | 11.09% | 3.81% |
| 11/10/1983 | 14.35% | 11.10% | 3.25% |
| 11/23/1983 | 16.00% | 11.13% | 4.87% |
| 11/23/1983 | 16.15% | 11.13% | 5.02% |
| 11/30/1983 | 15.00% | 11.14% | 3.86% |
| 12/5/1983 | 15.25% | 11.15% | 4.10% |
| 12/6/1983 | 15.07% | 11.16% | 3.91% |
| 12/8/1983 | 15.90% | 11.16% | 4.74% |
| 12/9/1983 | 14.75% | 11.17% | 3.58% |
| 12/12/1983 | 14.50% | 11.18% | 3.32% |
| 12/15/1983 | 15.56% | 11.20% | 4.36% |
| 12/19/1983 | 14.80% | 11.21% | 3.59% |
| 12/20/1983 | 14.69% | 11.22% | 3.47% |
| 12/20/1983 | 16.00% | 11.22% | 4.78% |
| 12/20/1983 | 16.25% | 11.22% | 5.03% |
| 12/22/1983 | 14.75% | 11.23% | 3.52% |
| 12/22/1983 | 15.75% | 11.23% | 4.52% |
| 1/3/1984 | 14.75% | 11.27% | 3.48% |
| 1/10/1984 | 15.90% | 11.30% | 4.60% |
| 1/12/1984 | 15.60% | 11.31% | 4.29% |
| 1/18/1984 | 13.75% | 11.33% | 2.42% |
| 1/19/1984 | 15.90% | 11.33% | 4.57% |
| 1/30/1984 | 16.10% | 11.37% | 4.73% |
| 1/31/1984 | 15.25% | 11.38% | 3.87% |
| 2/1/1984 | 14.80% | 11.39% | 3.41% |
| 2/6/1984 | 13.75% | 11.41% | 2.34% |
| 2/6/1984 | 14.75% | 11.41% | 3.34% |
| 2/9/1984 | 15.25% | 11.43% | 3.82% |
| 2/15/1984 | 15.70% | 11.45% | 4.25% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/22/1984 | 14.75% | 11.48% | 3.27% |
| 2/28/1984 | 14.50% | 11.52% | 2.98% |
| 3/2/1984 | 14.25% | 11.54% | 2.71% |
| 3/20/1984 | 16.00% | 11.65% | 4.35% |
| 3/23/1984 | 15.50% | 11.67% | 3.83% |
| 3/26/1984 | 14.71% | 11.68% | 3.03% |
| 4/2/1984 | 15.50% | 11.72% | 3.78% |
| 4/6/1984 | 14.74% | 11.76% | 2.98% |
| 4/11/1984 | 15.72% | 11.78% | 3.94% |
| 4/17/1984 | 15.00% | 11.81% | 3.19% |
| 4/18/1984 | 16.20% | 11.82% | 4.38% |
| 4/25/1984 | 14.64% | 11.85% | 2.79% |
| 4/30/1984 | 14.40% | 11.88% | 2.52% |
| 5/16/1984 | 14.69% | 11.99% | 2.70% |
| 5/16/1984 | 15.00% | 11.99% | 3.01% |
| 5/22/1984 | 14.40% | 12.02% | 2.38% |
| 5/29/1984 | 15.10% | 12.06% | 3.04% |
| 6/13/1984 | 15.25% | 12.16% | 3.09% |
| 6/15/1984 | 15.60% | 12.17% | 3.43% |
| 6/22/1984 | 16.25% | 12.21% | 4.04% |
| 6/29/1984 | 15.25% | 12.26% | 2.99% |
| 7/2/1984 | 13.35% | 12.27% | 1.08% |
| 7/10/1984 | 16.00% | 12.31% | 3.69% |
| 7/12/1984 | 16.50% | 12.33% | 4.17% |
| 7/13/1984 | 16.25% | 12.34% | 3.91% |
| 7/17/1984 | 14.14% | 12.35% | 1.79% |
| 7/18/1984 | 15.30% | 12.36% | 2.94% |
| 7/18/1984 | 15.50% | 12.36% | 3.14% |
| 7/19/1984 | 14.30% | 12.37% | 1.93% |
| 7/24/1984 | 16.79% | 12.40% | 4.39% |
| 7/31/1984 | 16.00% | 12.43% | 3.57% |
| 8/3/1984 | 14.25% | 12.45% | 1.80% |
| 8/17/1984 | 14.30% | 12.49% | 1.81% |
| 8/20/1984 | 15.00% | 12.49% | 2.51% |
| 8/27/1984 | 16.30% | 12.51% | 3.79% |
| 8/31/1984 | 15.55% | 12.53% | 3.02% |
| 9/6/1984 | 16.00% | 12.54% | 3.46% |
| 9/10/1984 | 14.75% | 12.55% | 2.20% |
| 9/13/1984 | 15.00% | 12.55% | 2.45% |
| 9/17/1984 | 17.38% | 12.56% | 4.82% |
| 9/26/1984 | 14.50% | 12.57% | 1.93% |
| 9/28/1984 | 15.00% | 12.57% | 2.43% |
| 9/28/1984 | 16.25% | 12.57% | 3.68% |
| 10/9/1984 | 14.75% | 12.58% | 2.17% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/12/1984 | 15.60% | 12.59% | 3.01% |
| 10/22/1984 | 15.00% | 12.59% | 2.41% |
| 10/26/1984 | 16.40% | 12.59% | 3.81% |
| 10/31/1984 | 16.25% | 12.59% | 3.66% |
| 11/7/1984 | 15.60% | 12.58% | 3.02% |
| 11/9/1984 | 16.00% | 12.58% | 3.42% |
| 11/14/1984 | 15.75% | 12.59% | 3.16% |
| 11/20/1984 | 15.25% | 12.58% | 2.67% |
| 11/20/1984 | 15.92% | 12.58% | 3.34% |
| 11/23/1984 | 15.00% | 12.58% | 2.42% |
| 11/28/1984 | 16.15% | 12.57% | 3.58% |
| 12/3/1984 | 15.80% | 12.57% | 3.23% |
| 12/4/1984 | 16.50% | 12.56% | 3.94% |
| 12/18/1984 | 16.40% | 12.54% | 3.86% |
| 12/19/1984 | 14.75% | 12.53% | 2.22% |
| 12/19/1984 | 15.00% | 12.53% | 2.47% |
| 12/20/1984 | 16.00% | 12.53% | 3.47% |
| 12/28/1984 | 16.00% | 12.50% | 3.50% |
| 1/3/1985 | 14.75% | 12.49% | 2.26% |
| 1/10/1985 | 15.75% | 12.47% | 3.28% |
| 1/11/1985 | 16.30% | 12.46% | 3.84% |
| 1/23/1985 | 15.80% | 12.43% | 3.37% |
| 1/24/1985 | 15.82% | 12.43% | 3.39% |
| 1/25/1985 | 16.75% | 12.42% | 4.33% |
| 1/30/1985 | 14.90% | 12.40% | 2.50% |
| 1/31/1985 | 14.75% | 12.39% | 2.36% |
| 2/8/1985 | 14.47% | 12.35% | 2.12% |
| 3/1/1985 | 13.84% | 12.30% | 1.54% |
| 3/8/1985 | 16.85% | 12.28% | 4.57% |
| 3/14/1985 | 15.50% | 12.25% | 3.25% |
| 3/15/1985 | 15.62% | 12.25% | 3.37% |
| 3/29/1985 | 15.62% | 12.16% | 3.46% |
| 4/3/1985 | 14.60% | 12.13% | 2.47% |
| 4/9/1985 | 15.50% | 12.10% | 3.40% |
| 4/16/1985 | 15.70% | 12.05% | 3.65% |
| 4/22/1985 | 14.00% | 12.01% | 1.99% |
| 4/26/1985 | 15.50% | 11.97% | 3.53% |
| 4/29/1985 | 15.00% | 11.96% | 3.04% |
| 5/2/1985 | 14.68% | 11.93% | 2.75% |
| 5/8/1985 | 15.62% | 11.88% | 3.74% |
| 5/10/1985 | 16.50% | 11.86% | 4.64% |
| 5/29/1985 | 14.61% | 11.73% | 2.88% |
| 5/31/1985 | 16.00% | 11.71% | 4.29% |
| 6/14/1985 | 15.50% | 11.60% | 3.90% |
| 7/9/1985 | 15.00% | 11.44% | 3.56% |
| 7/16/1985 | 14.50% | 11.39% | 3.11% |
| 7/26/1985 | 14.50% | 11.32% | 3.18% |
| 8/2/1985 | 14.80% | 11.29% | 3.51% |
| 8/7/1985 | 15.00% | 11.26% | 3.74% |
| 8/28/1985 | 14.25% | 11.15% | 3.10% |
| 8/28/1985 | 15.50% | 11.15% | 4.35% |
| 8/29/1985 | 14.50% | 11.14% | 3.36% |
| 9/9/1985 | 14.60% | 11.11% | 3.49% |
| 9/9/1985 | 14.90% | 11.11% | 3.79% |
| 9/17/1985 | 14.90% | 11.08% | 3.82% |
| 9/23/1985 | 15.00% | 11.06% | 3.94% |
| 9/27/1985 | 15.50% | 11.04% | 4.46% |
| 9/27/1985 | 15.80% | 11.04% | 4.76% |
| 10/2/1985 | 14.00% | 11.03% | 2.97% |
| 10/2/1985 | 14.75% | 11.03% | 3.72% |
| 10/3/1985 | 15.25% | 11.03% | 4.22% |
| 10/24/1985 | 15.40% | 10.96% | 4.44% |
| 10/24/1985 | 15.82% | 10.96% | 4.86% |
| 10/24/1985 | 15.85% | 10.96% | 4.89% |
| 10/28/1985 | 16.00% | 10.95% | 5.05% |
| 10/29/1985 | 16.65% | 10.94% | 5.71% |
| 10/31/1985 | 15.06% | 10.93% | 4.13% |
| 11/4/1985 | 14.50% | 10.91% | 3.59% |
| 11/7/1985 | 15.50% | 10.89% | 4.61% |
| 11/8/1985 | 14.30% | 10.89% | 3.41% |
| 12/12/1985 | 14.75% | 10.73% | 4.02% |
| 12/18/1985 | 15.00% | 10.69% | 4.31% |
| 12/20/1985 | 14.50% | 10.66% | 3.84% |
| 12/20/1985 | 14.50% | 10.66% | 3.84% |
| 12/20/1985 | 15.00% | 10.66% | 4.34% |
| 1/24/1986 | 15.40% | 10.40% | 5.00% |
| 1/31/1986 | 15.00% | 10.35% | 4.65% |
| 2/5/1986 | 15.00% | 10.32% | 4.68% |
| 2/5/1986 | 15.75% | 10.32% | 5.43% |
| 2/10/1986 | 13.30% | 10.29% | 3.01% |
| 2/11/1986 | 12.50% | 10.27% | 2.23% |
| 2/14/1986 | 14.40% | 10.24% | 4.16% |
| 2/18/1986 | 16.00% | 10.22% | 5.78% |
| 2/24/1986 | 14.50% | 10.17% | 4.33% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 2/26/1986 | 14.00% | 10.15% | 3.85% |
| 3/5/1986 | 14.90% | 10.07% | 4.83% |
| 3/11/1986 | 14.50% | 10.01% | 4.49% |
| 3/12/1986 | 13.50% | 10.00% | 3.50% |
| 3/27/1986 | 14.10% | 9.85% | 4.25% |
| 3/31/1986 | 13.50% | 9.84% | 3.66% |
| 4/1/1986 | 14.00% | 9.82% | 4.18% |
| 4/2/1986 | 15.50% | 9.81% | 5.69% |
| 4/4/1986 | 15.00% | 9.78% | 5.22% |
| 4/14/1986 | 13.40% | 9.68% | 3.72% |
| 4/23/1986 | 15.00% | 9.57% | 5.43% |
| 5/16/1986 | 14.50% | 9.31% | 5.19% |
| 5/16/1986 | 14.50% | 9.31% | 5.19% |
| 5/29/1986 | 13.90% | 9.19% | 4.71% |
| 5/30/1986 | 15.10% | 9.17% | 5.93% |
| 6/2/1986 | 12.81% | 9.16% | 3.65% |
| 6/11/1986 | 14.00% | 9.06% | 4.94% |
| 6/24/1986 | 16.63% | 8.93% | 7.70% |
| 6/26/1986 | 12.00% | 8.90% | 3.10% |
| 6/26/1986 | 14.75% | 8.90% | 5.85% |
| 6/30/1986 | 13.00% | 8.86% | 4.14% |
| 7/10/1986 | 14.34% | 8.74% | 5.60% |
| 7/11/1986 | 12.75% | 8.72% | 4.03% |
| 7/14/1986 | 12.60% | 8.71% | 3.89% |
| 7/17/1986 | 12.40% | 8.65% | 3.75% |
| 7/25/1986 | 14.25% | 8.56% | 5.69% |
| 8/6/1986 | 13.50% | 8.43% | 5.07% |
| 8/14/1986 | 13.50% | 8.34% | 5.16% |
| 9/16/1986 | 12.75% | 8.06% | 4.69% |
| 9/19/1986 | 13.25% | 8.02% | 5.23% |
| 10/1/1986 | 14.00% | 7.94% | 6.06% |
| 10/3/1986 | 13.40% | 7.92% | 5.48% |
| 10/31/1986 | 13.50% | 7.77% | 5.73% |
| 11/5/1986 | 13.00% | 7.74% | 5.26% |
| 12/3/1986 | 12.90% | 7.58% | 5.32% |
| 12/4/1986 | 14.44% | 7.57% | 6.87% |
| 12/16/1986 | 13.60% | 7.52% | 6.08% |
| 12/22/1986 | 13.80% | 7.50% | 6.30% |
| 12/30/1986 | 13.00% | 7.49% | 5.51% |
| 1/2/1987 | 13.00% | 7.48% | 5.52% |
| 1/12/1987 | 12.40% | 7.46% | 4.94% |
| 1/27/1987 | 12.71% | 7.46% | 5.25% |
| 3/2/1987 | 12.47% | 7.47% | 5.00% |
| 3/3/1987 | 13.60% | 7.47% | 6.13% |
| 3/4/1987 | 12.38% | 7.47% | 4.91% |
| 3/10/1987 | 13.50% | 7.47% | 6.03% |
| 3/13/1987 | 13.00% | 7.47% | 5.53% |
| 3/31/1987 | 13.00% | 7.46% | 5.54% |
| 4/6/1987 | 13.00% | 7.47% | 5.53% |
| 4/14/1987 | 12.50% | 7.49% | 5.01% |
| 4/16/1987 | 14.50% | 7.50% | 7.00% |
| 4/27/1987 | 12.00% | 7.54% | 4.46% |
| 5/5/1987 | 12.85% | 7.58% | 5.27% |
| 5/12/1987 | 12.65% | 7.62% | 5.03% |
| 5/28/1987 | 13.50% | 7.70% | 5.80% |
| 6/15/1987 | 13.20% | 7.78% | 5.42% |
| 6/29/1987 | 15.00% | 7.84% | 7.16% |
| 6/30/1987 | 12.50% | 7.84% | 4.66% |
| 7/8/1987 | 12.00% | 7.86% | 4.14% |
| 7/10/1987 | 12.90% | 7.87% | 5.03% |
| 7/15/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 15.00% | 7.88% | 7.12% |
| 7/27/1987 | 13.00% | 7.92% | 5.08% |
| 7/27/1987 | 13.40% | 7.92% | 5.48% |
| 7/27/1987 | 13.50% | 7.92% | 5.58% |
| 7/31/1987 | 12.98% | 7.95% | 5.03% |
| 8/26/1987 | 12.63% | 8.06% | 4.57% |
| 8/26/1987 | 12.75% | 8.06% | 4.69% |
| 8/27/1987 | 13.25% | 8.07% | 5.18% |
| 9/9/1987 | 13.00% | 8.14% | 4.86% |
| 9/30/1987 | 12.75% | 8.31% | 4.44% |
| 9/30/1987 | 13.00% | 8.31% | 4.69% |
| 10/2/1987 | 11.50% | 8.33% | 3.17% |
| 10/15/1987 | 13.00% | 8.44% | 4.56% |
| 11/2/1987 | 13.00% | 8.55% | 4.45% |
| 11/19/1987 | 13.00% | 8.64% | 4.36% |
| 11/30/1987 | 12.00% | 8.69% | 3.31% |
| 12/3/1987 | 14.20% | 8.71% | 5.49% |
| 12/15/1987 | 13.25% | 8.78% | 4.47% |
| 12/16/1987 | 13.50% | 8.79% | 4.71% |
| 12/16/1987 | 13.72% | 8.79% | 4.93% |
| 12/17/1987 | 11.75% | 8.80% | 2.95% |
| 12/18/1987 | 13.50% | 8.80% | 4.70% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/21/1987 | 12.01% | 8.81% | 3.20% |
| 12/22/1987 | 12.00% | 8.82% | 3.18% |
| 12/22/1987 | 12.00% | 8.82% | 3.18% |
| 12/22/1987 | 12.75% | 8.82% | 3.93% |
| 12/22/1987 | 13.00% | 8.82% | 4.18% |
| 1/20/1988 | 13.80% | 8.94% | 4.86% |
| 1/26/1988 | 13.90% | 8.96% | 4.94% |
| 1/29/1988 | 13.20% | 8.96% | 4.24% |
| 2/4/1988 | 12.60% | 8.96% | 3.64% |
| 3/1/1988 | 11.56% | 8.94% | 2.62% |
| 3/23/1988 | 12.87% | 8.92% | 3.95% |
| 3/24/1988 | 11.24% | 8.92% | 2.32% |
| 3/30/1988 | 12.72% | 8.92% | 3.80% |
| 4/1/1988 | 12.50% | 8.92% | 3.58% |
| 4/7/1988 | 13.25% | 8.93% | 4.32% |
| 4/25/1988 | 10.96% | 8.96% | 2.00% |
| 5/3/1988 | 12.91% | 8.98% | 3.93% |
| 5/11/1988 | 13.50% | 8.99% | 4.51% |
| 5/16/1988 | 13.00% | 8.99% | 4.01% |
| 6/30/1988 | 12.75% | 8.99% | 3.76% |
| 7/1/1988 | 12.75% | 8.99% | 3.76% |
| 7/20/1988 | 13.40% | 8.96% | 4.44% |
| 8/5/1988 | 12.75% | 8.91% | 3.84% |
| 8/23/1988 | 11.70% | 8.93% | 2.77% |
| 8/29/1988 | 12.75% | 8.94% | 3.81% |
| 8/30/1988 | 13.50% | 8.94% | 4.56% |
| 9/8/1988 | 12.60% | 8.95% | 3.65% |
| 10/13/1988 | 13.10% | 8.93% | 4.17% |
| 12/19/1988 | 13.00% | 9.02% | 3.98% |
| 12/20/1988 | 12.25% | 9.02% | 3.23% |
| 12/20/1988 | 13.00% | 9.02% | 3.98% |
| 12/21/1988 | 12.90% | 9.02% | 3.88% |
| 12/27/1988 | 13.00% | 9.03% | 3.97% |
| 12/28/1988 | 13.10% | 9.03% | 4.07% |
| 12/30/1988 | 13.40% | 9.04% | 4.36% |
| 1/27/1989 | 13.00% | 9.06% | 3.94% |
| 1/31/1989 | 13.00% | 9.06% | 3.94% |
| 2/17/1989 | 13.00% | 9.05% | 3.95% |
| 2/20/1989 | 12.40% | 9.05% | 3.35% |
| 3/1/1989 | 12.76% | 9.05% | 3.71% |
| 3/8/1989 | 13.00% | 9.05% | 3.95% |
| 3/30/1989 | 14.00% | 9.05% | 4.95% |
| 4/5/1989 | 14.20% | 9.05% | 5.15% |
| 4/18/1989 | 13.00% | 9.05% | 3.95% |
| 5/5/1989 | 12.40% | 9.05% | 3.35% |
| 6/2/1989 | 13.20% | 9.00% | 4.20% |
| 6/8/1989 | 13.50% | 8.98% | 4.52% |
| 6/27/1989 | 13.25% | 8.91% | 4.34% |
| 6/30/1989 | 13.00% | 8.90% | 4.10% |
| 8/14/1989 | 12.50% | 8.77% | 3.73% |
| 9/28/1989 | 12.25% | 8.63% | 3.62% |
| 10/24/1989 | 12.50% | 8.54% | 3.96% |
| 11/9/1989 | 13.00% | 8.48% | 4.52% |
| 12/15/1989 | 13.00% | 8.33% | 4.67% |
| 12/20/1989 | 12.90% | 8.31% | 4.59% |
| 12/21/1989 | 12.90% | 8.31% | 4.59% |
| 12/27/1989 | 12.50% | 8.29% | 4.21% |
| 12/27/1989 | 13.00% | 8.29% | 4.71% |
| 1/10/1990 | 12.80% | 8.24% | 4.56% |
| 1/11/1990 | 12.90% | 8.23% | 4.67% |
| 1/17/1990 | 12.80% | 8.22% | 4.58% |
| 1/26/1990 | 12.00% | 8.19% | 3.81% |
| 2/9/1990 | 12.10% | 8.17% | 3.93% |
| 2/24/1990 | 12.86% | 8.15% | 4.71% |
| 3/30/1990 | 12.90% | 8.16% | 4.74% |
| 4/4/1990 | 15.76% | 8.17% | 7.59% |
| 4/12/1990 | 12.52% | 8.18% | 4.34% |
| 4/19/1990 | 12.75% | 8.20% | 4.55% |
| 5/21/1990 | 12.10% | 8.28% | 3.82% |
| 5/29/1990 | 12.40% | 8.30% | 4.10% |
| 5/31/1990 | 12.00% | 8.30% | 3.70% |
| 6/4/1990 | 12.90% | 8.30% | 4.60% |
| 6/6/1990 | 12.25% | 8.31% | 3.94% |
| 6/15/1990 | 13.20% | 8.32% | 4.88% |
| 6/20/1990 | 12.92% | 8.32% | 4.60% |
| 6/27/1990 | 12.90% | 8.33% | 4.57% |
| 6/29/1990 | 12.50% | 8.34% | 4.16% |
| 7/6/1990 | 12.10% | 8.34% | 3.76% |
| 7/6/1990 | 12.35% | 8.34% | 4.01% |
| 8/10/1990 | 12.55% | 8.41% | 4.14% |
| 8/16/1990 | 13.21% | 8.43% | 4.78% |
| 8/22/1990 | 13.10% | 8.45% | 4.65% |
| 8/24/1990 | 13.00% | 8.46% | 4.54% |
| 9/26/1990 | 11.45% | 8.59% | 2.86% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/2/1990 | 13.00% | 8.61% | 4.39% |
| 10/5/1990 | 12.84% | 8.63% | 4.21% |
| 10/19/1990 | 13.00% | 8.67% | 4.33% |
| 10/25/1990 | 12.30% | 8.68% | 3.62% |
| 11/21/1990 | 12.70% | 8.69% | 4.01% |
| 12/13/1990 | 12.30% | 8.67% | 3.63% |
| 12/17/1990 | 12.87% | 8.67% | 4.20% |
| 12/18/1990 | 13.10% | 8.67% | 4.43% |
| 12/19/1990 | 12.00% | 8.66% | 3.34% |
| 12/20/1990 | 12.75% | 8.66% | 4.09% |
| 12/21/1990 | 12.50% | 8.66% | 3.84% |
| 12/27/1990 | 12.79% | 8.66% | 4.13% |
| 1/2/1991 | 13.10% | 8.66% | 4.44% |
| 1/4/1991 | 12.50% | 8.65% | 3.85% |
| 1/15/1991 | 12.75% | 8.65% | 4.10% |
| 1/25/1991 | 11.70% | 8.63% | 3.07% |
| 2/4/1991 | 12.50% | 8.60% | 3.90% |
| 2/7/1991 | 12.50% | 8.59% | 3.91% |
| 2/12/1991 | 13.00% | 8.57% | 4.43% |
| 2/14/1991 | 12.72% | 8.56% | 4.16% |
| 2/22/1991 | 12.80% | 8.55% | 4.25% |
| 3/6/1991 | 13.10% | 8.53% | 4.57% |
| 3/8/1991 | 12.30% | 8.52% | 3.78% |
| 3/8/1991 | 13.00% | 8.52% | 4.48% |
| 4/22/1991 | 13.00% | 8.49% | 4.51% |
| 5/7/1991 | 13.50% | 8.47% | 5.03% |
| 5/13/1991 | 13.25% | 8.47% | 4.78% |
| 5/30/1991 | 12.75% | 8.43% | 4.32% |
| 6/12/1991 | 12.00% | 8.41% | 3.59% |
| 6/25/1991 | 11.70% | 8.38% | 3.32% |
| 6/28/1991 | 12.50% | 8.38% | 4.12% |
| 7/1/1991 | 12.00% | 8.37% | 3.63% |
| 7/3/1991 | 12.50% | 8.36% | 4.14% |
| 7/19/1991 | 12.10% | 8.34% | 3.76% |
| 8/1/1991 | 12.90% | 8.32% | 4.58% |
| 8/16/1991 | 13.20% | 8.29% | 4.91% |
| 9/27/1991 | 12.50% | 8.23% | 4.27% |
| 9/30/1991 | 12.25% | 8.23% | 4.02% |
| 10/17/1991 | 13.00% | 8.20% | 4.80% |
| 10/23/1991 | 12.50% | 8.20% | 4.30% |
| 10/23/1991 | 12.55% | 8.20% | 4.35% |
| 10/31/1991 | 11.80% | 8.19% | 3.61% |
| 11/1/1991 | 12.00% | 8.19% | 3.81% |
| 11/5/1991 | 12.25% | 8.19% | 4.06% |
| 11/12/1991 | 12.50% | 8.18% | 4.32% |
| 11/12/1991 | 13.25% | 8.18% | 5.07% |
| 11/25/1991 | 12.40% | 8.18% | 4.22% |
| 11/26/1991 | 11.60% | 8.18% | 3.42% |
| 11/26/1991 | 12.50% | 8.18% | 4.32% |
| 11/27/1991 | 12.10% | 8.18% | 3.92% |
| 12/18/1991 | 12.25% | 8.15% | 4.10% |
| 12/19/1991 | 12.60% | 8.15% | 4.45% |
| 12/19/1991 | 12.80% | 8.15% | 4.65% |
| 12/20/1991 | 12.65% | 8.14% | 4.51% |
| 1/9/1992 | 12.80% | 8.09% | 4.71% |
| 1/16/1992 | 12.75% | 8.07% | 4.68% |
| 1/21/1992 | 12.00% | 8.06% | 3.94% |
| 1/22/1992 | 13.00% | 8.06% | 4.94% |
| 1/27/1992 | 12.65% | 8.05% | 4.60% |
| 1/31/1992 | 12.00% | 8.04% | 3.96% |
| 2/11/1992 | 12.40% | 8.03% | 4.37% |
| 2/25/1992 | 12.50% | 8.01% | 4.49% |
| 3/16/1992 | 11.43% | 7.98% | 3.45% |
| 3/18/1992 | 12.28% | 7.98% | 4.30% |
| 4/2/1992 | 12.10% | 7.95% | 4.15% |
| 4/9/1992 | 11.45% | 7.93% | 3.52% |
| 4/10/1992 | 11.50% | 7.93% | 3.57% |
| 4/14/1992 | 11.50% | 7.92% | 3.58% |
| 5/5/1992 | 11.50% | 7.89% | 3.61% |
| 5/12/1992 | 11.87% | 7.88% | 3.99% |
| 5/12/1992 | 12.46% | 7.88% | 4.58% |
| 6/1/1992 | 12.30% | 7.86% | 4.44% |
| 6/12/1992 | 10.90% | 7.85% | 3.05% |
| 6/26/1992 | 12.35% | 7.85% | 4.50% |
| 6/29/1992 | 11.00% | 7.85% | 3.15% |
| 6/30/1992 | 13.00% | 7.85% | 5.15% |
| 7/13/1992 | 11.90% | 7.84% | 4.06% |
| 7/13/1992 | 13.50% | 7.84% | 5.66% |
| 7/22/1992 | 11.20% | 7.83% | 3.37% |
| 8/3/1992 | 12.00% | 7.81% | 4.19% |
| 8/6/1992 | 12.50% | 7.80% | 4.70% |
| 9/22/1992 | 12.00% | 7.71% | 4.29% |
| 9/28/1992 | 11.40% | 7.71% | 3.69% |
| 9/30/1992 | 11.75% | 7.71% | 4.04% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/2/1992 | 13.00% | 7.70% | 5.30% |
| 10/12/1992 | 12.20% | 7.70% | 4.50% |
| 10/16/1992 | 13.16% | 7.71% | 5.45% |
| 10/30/1992 | 11.75% | 7.71% | 4.04% |
| 11/3/1992 | 12.00% | 7.71% | 4.29% |
| 12/3/1992 | 11.85% | 7.68% | 4.17% |
| 12/15/1992 | 11.00% | 7.66% | 3.34% |
| 12/16/1992 | 11.90% | 7.66% | 4.24% |
| 12/16/1992 | 12.40% | 7.66% | 4.74% |
| 12/17/1992 | 12.00% | 7.66% | 4.34% |
| 12/22/1992 | 12.30% | 7.65% | 4.65% |
| 12/22/1992 | 12.40% | 7.65% | 4.75% |
| 12/29/1992 | 12.25% | 7.63% | 4.62% |
| 12/30/1992 | 12.00% | 7.63% | 4.37% |
| 12/31/1992 | 11.90% | 7.62% | 4.28% |
| 1/12/1993 | 12.00% | 7.61% | 4.39% |
| 1/21/1993 | 11.25% | 7.59% | 3.66% |
| 2/2/1993 | 11.40% | 7.56% | 3.84% |
| 2/15/1993 | 12.30% | 7.52% | 4.78% |
| 2/24/1993 | 11.90% | 7.49% | 4.41% |
| 2/26/1993 | 11.80% | 7.48% | 4.32% |
| 2/26/1993 | 12.20% | 7.48% | 4.72% |
| 4/23/1993 | 11.75% | 7.29% | 4.46% |
| 5/11/1993 | 11.75% | 7.24% | 4.51% |
| 5/14/1993 | 11.50% | 7.24% | 4.26% |
| 5/25/1993 | 11.50% | 7.22% | 4.28% |
| 5/28/1993 | 11.00% | 7.22% | 3.78% |
| 6/3/1993 | 12.00% | 7.21% | 4.79% |
| 6/16/1993 | 11.50% | 7.19% | 4.31% |
| 6/18/1993 | 12.10% | 7.18% | 4.92% |
| 6/25/1993 | 11.67% | 7.17% | 4.50% |
| 7/21/1993 | 11.38% | 7.10% | 4.28% |
| 7/23/1993 | 10.46% | 7.09% | 3.37% |
| 8/24/1993 | 11.50% | 6.95% | 4.55% |
| 9/21/1993 | 10.50% | 6.80% | 3.70% |
| 9/29/1993 | 11.47% | 6.76% | 4.71% |
| 9/30/1993 | 11.60% | 6.76% | 4.84% |
| 11/2/1993 | 10.80% | 6.60% | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | 3.45% |
| 11/18/1994 | 11.20% | 7.46% | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | 3.55% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/9/1995 | 11.25% | 7.60% | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | 4.47% |
| 12/18/1996 | 11.75% | 6.84% | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | 4.98% |
| 2/20/1997 | 11.80% | 6.82% | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | 7.00% |
| 1/22/2002 | 10.00% | 5.50% | 4.50% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/27/2002 | 10.10% | 5.45% | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | 5.56% |
| 1/13/2004 | 12.00% | 4.95% | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | 6.43% |
| 12/29/2004 | 9.85% | 5.08% | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | 5.58% |
| 4/26/2006 | 10.60% | 4.64% | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | 6.91% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/6/2006 | 10.00% | 4.75% | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | 5.45% |
| 5/22/2007 | 10.20% | 4.80% | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | 5.69% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 11/13/2008 | 10.55% | 4.45% | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | 6.68% |
| 10/23/2009 | 10.88% | 4.06% | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | 5.42% |
| 8/25/2010 | 9.90% | 4.37% | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | 5.68% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/16/2010 | 10.00% | 4.32% | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | 5.89% |
| 2/25/2011 | 10.00% | 4.14% | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | 7.06% |
| 4/4/2012 | 10.00% | 3.29% | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | 6.96% |
| 7/9/2012 | 10.20% | 3.03% | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | 6.86% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/19/2012 | 9.80% | 2.94% | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | 7.58% |
| 12/21/2012 | 10.20% | 2.87% | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | 6.73% |
| 6/30/2014 | 9.55% | 3.64% | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | 6.30% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 8/20/2014 | 9.75% | 3.56% | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | 6.77% |
| 4/23/2015 | 10.20% | 2.87% | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | 7.05% |
| 9/30/2016 | 9.90% | 2.53% | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | 7.50% |
| 2/15/2017 | 9.60% | 2.62% | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | 7.53% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 4/12/2017 | 9.40% | 2.74% | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 12/5/2017 | 9.50% | 2.88% | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | 6.53% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | 6.81% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 8/12/2019 | 9.60% | 2.89% | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | 7.40% |
| 11/7/2019 | 9.35% | 2.58% | 6.77% |
| 11/29/2019 | 9.50% | 2.52% | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | 7.04% |
| 1/8/2020 | 10.02% | 2.43% | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | 7.63% |
| | | Average | 4.72% |
| | | Count | 1625 |

Expected Earnings Analysis

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| | | Expected ROE | Shares Outstanding | | | Adjustment | Adjusted |
| Company | Ticker | 2022-2024/ 2023-2025 | 2020 | 2022-2024/ 2023-2025 | % Increase | Factor | ROE |
| ALLETE, Inc. | ALE | 8.50% | 52.00 | 53.00 | 0.38% | 1.002 | 8.52% |
| Alliant Energy Corporation | LNT | 10.50% | 248.00 | 260.00 | 0.95% | 1.005 | 10.55% |
| Ameren Corporation | AEE | 10.00% | 254.00 | 275.00 | 1.60% | 1.008 | 10.08% |
| American Electric Power Company, Inc. | AEP | 10.50% | 495.00 | 530.00 | 1.38% | 1.007 | 10.57% |
| Avangrid, Inc. | AGR | 6.00% | 309.00 | 309.00 | 0.00% | 1.000 | 6.00% |
| Avista | AVA | 8.00% | 68.00 | 71.00 | 1.09% | 1.005 | 8.04% |
| CMS Energy Corporation | CMS | 13.50% | 287.00 | 300.00 | 0.89% | 1.004 | 13.56% |
| DTE Energy Company | DTE | 10.50% | 194.00 | 206.00 | 1.21% | 1.006 | 10.56% |
| Evergy, Inc | EVRG | 8.50% | 227.00 | 227.00 | 0.00% | 1.000 | 8.50% |
| Hawaiian Electric Industries, Inc. | HE | 9.00% | 110.00 | 113.00 | 0.67% | 1.003 | 9.03% |
| NextEra Energy, Inc. | NEE | 13.00% | 489.00 | 495.00 | 0.24% | 1.001 | 13.02% |
| NorthWestern Corporation | NWE | 9.00% | 50.90 | 51.60 | 0.34% | 1.002 | 9.02% |
| OGE Energy Corp. | OGE | 11.00% | 200.00 | 200.00 | 0.00% | 1.000 | 11.00% |
| Otter Tail Corporation | OTTR | 11.50% | 41.00 | 41.50 | 0.24% | 1.001 | 11.51% |
| Pinnacle West Capital Corporation | PNW | 10.00% | 113.50 | 118.00 | 0.98% | 1.005 | 10.05% |
| PNM Resources, Inc. | PNM | 9.00% | 79.65 | 90.00 | 3.10% | 1.015 | 9.14% |
| Portland General Electric Company | POR | 9.00% | 89.55 | 90.00 | 0.13% | 1.001 | 9.01% |
| Southern Company | SO | 13.00% | 1050.00 | 1080.00 | 0.57% | 1.003 | 13.04% |
| WEC Energy Group, Inc. | WEC | 12.50% | 315.50 | 315.50 | 0.00% | 1.000 | 12.50% |
| Xcel Energy Inc. | XEL | 10.50% | 539.00 | 546.00 | 0.32% | 1.002 | 10.52% |
| | | | | | | Median | 10.30% |
| | | | | | | Average | 10.21% |

Notes:

[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals =([3] / [2])^(1/4)-1; ([3] / [2])^(1/5)-1
[5] Equals (2 x (1 + [4])) / (2 + [4])
[6] Equals [1] x [5]

Proxy Group Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 58.68% | 59.66% | 59.53% | 59.12% | 58.50% | 58.84% | 63.09% | 62.51% | 59.99% |
| Alliant Energy Corporation | LNT | 51.73% | 50.38% | 53.18% | 53.11% | 51.13% | 51.00% | 49.74% | 49.77% | 51.26% |
| Ameren Corporation | AEE | 53.67% | 53.03% | 52.81% | 52.69% | 53.22% | 52.01% | 53.04% | 52.65% | 52.89% |
| American Electric Power Company, Inc. | AEP | 49.91% | 48.80% | 49.62% | 49.40% | 48.68% | 48.52% | 48.60% | 48.91% | 49.06% |
| Avangrid, Inc. | AGR | 54.38% | 56.33% | 56.51% | 55.72% | 56.13% | 54.93% | 56.55% | 55.69% | 55.78% |
| Avista Corporation | AVA | 55.80% | 56.32% | 56.10% | 55.09% | 55.75% | 55.76% | 56.34% | 55.76% | 55.86% |
| CMS Energy Corporation | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| DTE Energy Company | DTE | 49.40% | 48.76% | 48.69% | 50.96% | 49.97% | 49.23% | 51.12% | 51.02% | 49.89% |
| Evergy, Inc. | EVRG | 60.28% | 60.51% | 58.16% | 59.56% | 59.86% | 58.51% | 58.73% | 58.62% | 59.28% |
| Hawaiian Electric Industries, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| NextEra Energy, Inc. | NEE | 56.15% | 61.22% | 61.05% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 61.20% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| OGE Energy Corp. | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Corporation | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Pinnacle West Capital Corporation | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| PNM Resources, Inc. | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Southern Company | SO | 52.36% | 52.93% | 52.80% | 54.21% | 51.50% | 50.31% | 49.98% | 47.67% | 51.47% |
| Wisconsin Energy Corporation | WEC | 55.79% | 56.71% | 55.73% | 53.46% | 58.30% | 57.72% | 61.62% | 54.62% | 56.74% |
| Xcel Energy Inc. | XEL | 53.98% | 54.70% | 54.51% | 54.22% | 53.37% | 53.63% | 54.15% | 53.95% | 54.06% |
| Mean | | 53.59% | 53.81% | 53.79% | 53.75% | 53.87% | 53.32% | 53.90% | 53.52% | 53.69% |
| | | | | | | | | | | 45.65% |
| | | | | | | | | | | 61.20% |

Operating Company Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 59.33% | 60.94% | 60.87% | 61.39% | 60.43% | 60.33% | 60.38% | 60.04% | 60.46% |
| Superior Water, Light and Power Company | ALE | 58.03% | 58.38% | 58.19% | 56.86% | 56.58% | 57.34% | 65.80% | 64.99% | 59.52% |
| Interstate Power and Light Company | LNT | 50.06% | 51.76% | 53.33% | 53.52% | 49.64% | 50.47% | 49.92% | 50.31% | 51.13% |
| Wisconsin Power and Light Company | LNT | 53.40% | 49.01% | 53.03% | 52.69% | 52.62% | 51.52% | 49.57% | 49.23% | 51.38% |
| Ameren Illinois Company | AEE | 54.46% | 54.05% | 53.65% | 52.86% | 53.18% | 52.74% | 54.24% | 53.38% | 53.57% |
| Union Electric Company | AEE | 52.88% | 52.00% | 51.96% | 52.52% | 53.26% | 51.28% | 51.84% | 51.92% | 52.21% |
| AEP Texas Inc. | AEP | 46.97% | 46.32% | 47.54% | 45.38% | 43.80% | 43.20% | 46.75% | 45.14% | 45.64% |
| Appalachian Power Company | AEP | 48.74% | 48.19% | 47.77% | 49.51% | 49.30% | 48.93% | 49.35% | 48.72% | 48.81% |
| Indiana Michigan Power Company | AEP | 46.51% | 45.83% | 45.43% | 44.62% | 44.53% | 44.15% | 46.64% | 46.33% | 45.50% |
| Kentucky Power Company | AEP | 46.94% | 46.50% | 46.42% | 45.72% | 45.28% | 44.89% | 44.40% | 43.52% | 45.46% |
| Kingsport Power Company | AEP | 54.24% | 50.18% | 51.54% | 50.79% | 50.71% | 47.69% | 47.28% | 46.53% | 49.87% |
| Ohio Power Company | AEP | 53.63% | 52.92% | 58.86% | 57.80% | 56.85% | 57.11% | 52.91% | 58.63% | 56.09% |
| Public Service Company of Oklahoma | AEP | 49.89% | 48.02% | 47.19% | 49.16% | 49.55% | 48.59% | 48.10% | 48.50% | 48.62% |
| Southwestern Electric Power Company | AEP | 48.63% | 47.45% | 47.59% | 46.97% | 43.43% | 47.91% | 47.72% | 48.52% | 47.28% |
| Wheeling Power Company | AEP | 53.66% | 53.83% | 54.27% | 54.62% | 54.70% | 54.19% | 54.27% | 54.26% | 54.23% |
| Central Maine Power Company | AGR | 62.19% | 61.96% | 63.51% | 63.21% | 64.17% | 63.53% | 64.18% | 63.82% | 63.32% |
| New York State Electric & Gas Corporation | AGR | 48.79% | 55.84% | 55.93% | 54.30% | 53.95% | 50.99% | 54.51% | 53.30% | 53.45% |
| Rochester Gas and Electric Corporation | AGR | 50.50% | 50.25% | 49.96% | 48.89% | 48.16% | 47.77% | 50.80% | 49.63% | 49.50% |
| United Illuminating Company | AGR | 56.05% | 57.26% | 56.65% | 56.46% | 58.23% | 57.43% | 56.70% | 56.00% | 56.85% |
| Alaska Electric Light and Power Company | AVA | 61.28% | 61.24% | 61.02% | 60.29% | 61.94% | 61.78% | 61.53% | 60.77% | 61.23% |
| Avista Corporation | AVA | 50.33% | 51.40% | 51.18% | 49.89% | 49.55% | 49.74% | 51.16% | 50.75% | 50.50% |
| Consumers Energy Company | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| DTE Electric Company | DTE | 49.40% | 48.76% | 48.69% | 50.96% | 49.97% | 49.23% | 51.12% | 51.02% | 49.89% |
| Evergy Kansas South, Inc. | EVRG | 81.84% | 81.49% | 75.13% | 74.97% | 74.91% | 74.45% | 74.29% | 74.18% | 76.41% |
| Evergy Metro, Inc. | EVRG | 50.43% | 49.62% | 46.04% | 49.49% | 49.50% | 48.88% | 49.25% | 49.15% | 49.05% |
| Evergy Missouri West, Inc. | EVRG | 51.18% | 51.74% | 52.68% | 54.71% | 55.70% | 52.03% | 52.63% | 52.40% | 52.88% |
| Westar Energy (KPL) | EVRG | 57.66% | 59.18% | 58.80% | 59.08% | 59.34% | 58.68% | 58.75% | 58.74% | 58.78% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Florida Power & Light Company | NEE | 59.78% | 61.30% | 64.03% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 62.03% |
| Gulf Power Company | NEE | 52.52% | 61.15% | 58.06% | NA | NA | NA | NA | NA | 57.24% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| Oklahoma Gas and Electric Company | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Power Company | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Arizona Public Service Company | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| Public Service Company of New Mexico | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Alabama Power Company | SO | 51.45% | 52.54% | 52.23% | 47.77% | 48.13% | 47.51% | 48.86% | 47.07% | 49.44% |
| Georgia Power Company | SO | 55.38% | 56.39% | 56.43% | 59.02% | 57.27% | 54.97% | 53.81% | 50.06% | 55.42% |
| Gulf Power Company | SO | NA | NA | NA | 59.73% | 55.34% | 54.90% | 54.27% | 54.19% | 55.69% |
| Mississippi Power Company | SO | 50.23% | 49.87% | 49.73% | 50.35% | 45.28% | 43.87% | 43.00% | 39.34% | 46.46% |
| Upper Michigan Energy Resources Corporation | WEC | 56.09% | 54.45% | 52.54% | 47.01% | 55.08% | 54.53% | 70.04% | 49.85% | 54.95% |
| Wisconsin Electric Power Company | WEC | 56.92% | 56.64% | 55.78% | 56.03% | 59.25% | 59.09% | 56.47% | 55.94% | 57.01% |
| Wisconsin Public Service Corporation | WEC | 54.37% | 59.04% | 58.88% | 57.33% | 60.59% | 59.53% | 58.35% | 58.06% | 58.27% |
| Northern States Power Company - MN | XEL | 51.79% | 53.66% | 53.64% | 52.81% | 52.64% | 52.61% | 52.59% | 52.38% | 52.77% |
| Northern States Power Company - WI | XEL | 53.56% | 53.49% | 53.59% | 53.60% | 48.45% | 53.85% | 53.79% | 53.36% | 52.96% |
| Public Service Company of Colorado | XEL | 56.35% | 57.53% | 56.68% | 56.31% | 56.08% | 54.17% | 56.67% | 56.50% | 56.29% |
| Southwestern Public Service Company | XEL | 54.21% | 54.14% | 54.13% | 54.17% | 56.29% | 53.88% | 53.54% | 53.55% | 54.24% |
| Mean | | 53.68% | 53.94% | 53.92% | 53.66% | 53.58% | 53.04% | 53.71% | 53.03% | 53.63% |
| | | | | | | | | | | 45.46% |
| Source: S&P Global Market Intelligence | | | | | | | | | | 76.41% |

Proxy Group Capital Structure

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 41.32% | 40.34% | 40.47% | 40.88% | 41.50% | 41.16% | 36.91% | 37.49% | 40.01% |
| Alliant Energy Corporation | LNT | 48.27% | 49.62% | 46.82% | 46.89% | 48.87% | 49.00% | 50.26% | 50.23% | 48.74% |
| Ameren Corporation | AEE | 46.33% | 46.97% | 47.19% | 47.31% | 46.78% | 47.99% | 46.96% | 47.35% | 47.11% |
| American Electric Power Company, Inc. | AEP | 50.09% | 51.20% | 50.38% | 50.60% | 51.32% | 51.48% | 51.40% | 51.09% | 50.94% |
| Avangrid, Inc. | AGR | 45.62% | 43.67% | 43.49% | 44.28% | 43.87% | 45.07% | 43.45% | 44.31% | 44.22% |
| Avista Corporation | AVA | 44.20% | 43.68% | 43.90% | 44.91% | 44.25% | 44.24% | 43.66% | 44.24% | 44.14% |
| CMS Energy Corporation | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| DTE Energy Company | DTE | 50.60% | 51.24% | 51.31% | 49.04% | 50.03% | 50.77% | 48.88% | 48.98% | 50.11% |
| Evergy, Inc. | EVRG | 39.72% | 39.49% | 41.84% | 40.44% | 40.14% | 41.49% | 41.27% | 41.38% | 40.72% |
| Hawaiian Electric Industries, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| NextEra Energy, Inc. | NEE | 43.85% | 38.78% | 38.95% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 38.80% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| OGE Energy Corp. | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Corporation | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Pinnacle West Capital Corporation | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| PNM Resources, Inc. | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Southern Company | SO | 47.64% | 47.07% | 47.20% | 45.79% | 48.50% | 49.69% | 50.02% | 52.33% | 48.53% |
| Wisconsin Energy Corporation | WEC | 44.21% | 43.29% | 44.27% | 46.54% | 41.70% | 42.28% | 38.38% | 45.38% | 43.26% |
| Xcel Energy Inc. | XEL | 46.02% | 45.30% | 45.49% | 45.78% | 46.63% | 46.37% | 45.85% | 46.05% | 45.94% |
| Mean | | 46.41% | 46.19% | 46.21% | 46.25% | 46.13% | 46.68% | 46.10% | 46.48% | 46.31% |

Operating Company Capital Structure

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 40.67% | 39.06% | 39.13% | 38.61% | 39.57% | 39.67% | 39.62% | 39.96% | 39.54% |
| Superior Water, Light and Power Company | ALE | 41.97% | 41.62% | 41.81% | 43.14% | 43.42% | 42.66% | 34.20% | 35.01% | 40.48% |
| Interstate Power and Light Company | LNT | 49.94% | 48.24% | 46.67% | 46.48% | 50.36% | 49.53% | 50.08% | 49.69% | 48.87% |
| Wisconsin Power and Light Company | LNT | 46.60% | 50.99% | 46.97% | 47.31% | 47.38% | 48.48% | 50.43% | 50.77% | 48.62% |
| Ameren Illinois Company | AEE | 45.54% | 45.95% | 46.35% | 47.14% | 46.82% | 47.26% | 45.76% | 46.62% | 46.43% |
| Union Electric Company | AEE | 47.12% | 48.00% | 48.04% | 47.48% | 46.74% | 48.72% | 48.16% | 48.08% | 47.79% |
| AEP Texas Inc. | AEP | 53.03% | 53.68% | 52.46% | 54.62% | 56.20% | 56.80% | 53.25% | 54.86% | 54.36% |
| Appalachian Power Company | AEP | 51.26% | 51.81% | 52.23% | 50.49% | 50.70% | 51.07% | 50.65% | 51.28% | 51.19% |
| Indiana Michigan Power Company | AEP | 53.49% | 54.17% | 54.57% | 55.38% | 55.47% | 55.85% | 53.36% | 53.67% | 54.50% |
| Kentucky Power Company | AEP | 53.06% | 53.50% | 53.58% | 54.28% | 54.72% | 55.11% | 55.60% | 56.48% | 54.54% |
| Kingsport Power Company | AEP | 45.76% | 49.82% | 48.46% | 49.21% | 49.29% | 52.31% | 52.72% | 53.47% | 50.13% |
| Ohio Power Company | AEP | 46.37% | 47.08% | 41.14% | 42.20% | 43.15% | 42.89% | 47.09% | 41.37% | 43.91% |
| Public Service Company of Oklahoma | AEP | 50.11% | 51.98% | 52.81% | 50.84% | 50.45% | 51.41% | 51.90% | 51.50% | 51.38% |
| Southwestern Electric Power Company | AEP | 51.37% | 52.55% | 52.41% | 53.03% | 56.57% | 52.09% | 52.28% | 51.48% | 52.72% |
| Wheeling Power Company | AEP | 46.34% | 46.17% | 45.73% | 45.38% | 45.30% | 45.81% | 45.73% | 45.74% | 45.77% |
| Central Maine Power Company | AGR | 37.81% | 38.04% | 36.49% | 36.79% | 35.83% | 36.47% | 35.82% | 36.18% | 36.68% |
| New York State Electric & Gas Corporation | AGR | 51.21% | 44.16% | 44.07% | 45.70% | 46.05% | 49.01% | 45.49% | 46.70% | 46.55% |
| Rochester Gas and Electric Corporation | AGR | 49.50% | 49.75% | 50.04% | 51.11% | 51.84% | 52.23% | 49.20% | 50.37% | 50.50% |
| United Illuminating Company | AGR | 43.95% | 42.74% | 43.35% | 43.54% | 41.77% | 42.57% | 43.30% | 44.00% | 43.15% |
| Alaska Electric Light and Power Company | AVA | 38.72% | 38.76% | 38.98% | 39.71% | 38.06% | 38.22% | 38.47% | 39.23% | 38.77% |
| Avista Corporation | AVA | 49.67% | 48.60% | 48.82% | 50.11% | 50.45% | 50.26% | 48.84% | 49.25% | 49.50% |
| Consumers Energy Company | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| DTE Electric Company | DTE | 50.60% | 51.24% | 51.31% | 49.04% | 50.03% | 50.77% | 48.88% | 48.98% | 50.11% |
| Evergy Kansas South, Inc. | EVRG | 18.16% | 18.51% | 24.87% | 25.03% | 25.09% | 25.55% | 25.71% | 25.82% | 23.59% |
| Evergy Metro, Inc. | EVRG | 49.57% | 50.38% | 53.96% | 50.51% | 50.50% | 51.12% | 50.75% | 50.85% | 50.95% |
| Evergy Missouri West, Inc. | EVRG | 48.82% | 48.26% | 47.32% | 45.29% | 44.30% | 47.97% | 47.37% | 47.60% | 47.12% |
| Westar Energy (KPL) | EVRG | 42.34% | 40.82% | 41.20% | 40.92% | 40.66% | 41.32% | 41.25% | 41.26% | 41.22% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Florida Power & Light Company | NEE | 40.22% | 38.70% | 35.97% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 37.97% |
| Gulf Power Company | NEE | 47.48% | 38.85% | 41.94% | NA | NA | NA | NA | NA | 42.76% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| Oklahoma Gas and Electric Company | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Power Company | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Arizona Public Service Company | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| Public Service Company of New Mexico | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Alabama Power Company | SO | 48.55% | 47.46% | 47.77% | 52.23% | 51.87% | 52.49% | 51.14% | 52.93% | 50.56% |
| Georgia Power Company | SO | 44.62% | 43.61% | 43.57% | 40.98% | 42.73% | 45.03% | 46.19% | 49.94% | 44.58% |
| Gulf Power Company | SO | NA | NA | NA | 40.27% | 44.66% | 45.10% | 45.73% | 45.81% | 44.31% |
| Mississippi Power Company | SO | 49.77% | 50.13% | 50.27% | 49.65% | 54.72% | 56.13% | 57.00% | 60.66% | 53.54% |
| Upper Michigan Energy Resources Corporation | WEC | 43.91% | 45.55% | 47.46% | 52.99% | 44.92% | 45.47% | 29.96% | 50.15% | 45.05% |
| Wisconsin Electric Power Company | WEC | 43.08% | 43.36% | 44.22% | 43.97% | 40.75% | 40.91% | 43.53% | 44.06% | 42.99% |
| Wisconsin Public Service Corporation | WEC | 45.63% | 40.96% | 41.12% | 42.67% | 39.41% | 40.47% | 41.65% | 41.94% | 41.73% |
| Northern States Power Company - MN | XEL | 48.21% | 46.34% | 46.36% | 47.19% | 47.36% | 47.39% | 47.41% | 47.62% | 47.23% |
| Northern States Power Company - WI | XEL | 46.44% | 46.51% | 46.41% | 46.40% | 51.55% | 46.15% | 46.21% | 46.64% | 47.04% |
| Public Service Company of Colorado | XEL | 43.65% | 42.47% | 43.32% | 43.69% | 43.92% | 45.83% | 43.33% | 43.50% | 43.71% |
| Southwestern Public Service Company | XEL | 45.79% | 45.86% | 45.87% | 45.83% | 43.71% | 46.12% | 46.46% | 46.45% | 45.76% |
| Mean | | 46.32% | 46.06% | 46.08% | 46.34% | 46.42% | 46.96% | 46.29% | 46.97% | 46.37% |

2015-2020 Authorized Returns on Equity, Vertically Integrated Electric Utitlity Rate Cases

| State | Utility | Parent Company Ticker | Case Identification | Date Authorized | Authorized ROE |
|---|---|---|---|---|---|
| Wyoming | PacifiCorp | BRK.A | D-20000-446-ER-14 | 1/23/2015 | 9.50 |
| Colorado | Public Service Co. of CO | XEL | D-14AL-0660E | 2/24/2015 | 9.83 |
| Washington | PacifiCorp | BRK.A | D-UE-140762 | 3/25/2015 | 9.50 |
| Minnesota | Northern States Power Co. - MN | XEL | D-E-002/GR-13-868 | 3/26/2015 | 9.72 |
| Michigan | Wisconsin Public Service Corp. | WEC | C-U-17669 | 4/23/2015 | 10.20 |
| Missouri | Union Electric Co. | AEE | C-ER-2014-0258 | 4/29/2015 | 9.53 |
| West Virginia | Appalachian Power Co. | AEP | C-14-1152-E-42T | 5/26/2015 | 9.75 |
| Missouri | Kansas City Power & Light | GXP | C-ER-2014-0370 | 9/2/2015 | 9.50 |
| Kansas | Kansas City Power & Light | GXP | D-15-KCPE-116-RTS | 9/10/2015 | 9.30 |
| Wisconsin | Wisconsin Public Service Corp. | WEC | D-6690-UR-124 (Elec) | 11/19/2015 | 10.00 |
| Michigan | Consumers Energy Co. | CMS | C-U-17735 | 11/19/2015 | 10.30 |
| Wisconsin | Northern States Power Co - WI | XEL | D-4220-UR-121 (Elec) | 12/3/2015 | 10.00 |
| Michigan | DTE Electric Co. | DTE | C-U-17767 | 12/11/2015 | 10.30 |
| Oregon | Portland General Electric Co. | POR | D-UE-294 | 12/15/2015 | 9.60 |
| Texas | Southwestern Public Service Co | XEL | D-43695 | 12/17/2015 | 9.70 |
| Idaho | Avista Corp. | AVA | C-AVU-E-15-05 | 12/18/2015 | 9.50 |
| Wyoming | PacifiCorp | BRK.A | D-20000-469-ER-15 | 12/30/2015 | 9.50 |
| Washington | Avista Corp. | AVA | D-UE-150204 | 1/6/2016 | 9.50 |
| Arkansas | Entergy Arkansas Inc. | ETR | D-15-015-U | 2/23/2016 | 9.75 |
| Indiana | Indianapolis Power & Light Co. | AES | Ca-44576 | 3/16/2016 | 9.85 |
| New Mexico | El Paso Electric Co. | EE | C-15-00127-UT | 6/8/2016 | 9.48 |
| Indiana | Northern IN Public Svc Co. | NI | Ca-44688 | 7/18/2016 | 9.98 |
| Tennessee | Kingsport Power Company | AEP | D-16-00001 | 8/9/2016 | 9.85 |
| Arizona | UNS Electric Inc. | FTS | D-E-04204A-15-0142 | 8/18/2016 | 9.50 |
| Washington | PacifiCorp | BRK.A | D-UE-152253 | 9/1/2016 | 9.50 |
| Michigan | Upper Peninsula Power Co. | - | C-U-17895 | 9/8/2016 | 10.00 |
| New Mexico | Public Service Co. of NM | PNM | C-15-00261-UT | 9/28/2016 | 9.58 |
| Wisconsin | Madison Gas and Electric Co. | MGEE | D-3270-UR-121 (Elec) | 11/9/2016 | 9.80 |
| Oklahoma | Public Service Co. of OK | AEP | Ca-PUD201500208 | 11/10/2016 | 9.50 |
| Wisconsin | Wisconsin Power and Light Co | LNT | D-6680-UR-120 (Elec) | 11/18/2016 | 10.00 |
| Florida | Florida Power & Light Co. | NEE | D-160021-EI | 11/29/2016 | 10.55 |
| California | Liberty Utilities CalPeco Ele | AQN | A-15-05-008 | 12/1/2016 | 10.00 |
| South Carolina | Duke Energy Progress LLC | DUK | D-2016-227-E | 12/7/2016 | 10.10 |
| Colorado | Black Hills Colorado Electric | BKH | D-16AL-0326E | 12/19/2016 | 9.37 |
| North Carolina | Virginia Electric & Power Co. | D | D-E-22, Sub 532 | 12/22/2016 | 9.90 |
| Nevada | Sierra Pacific Power Co. | BRK.A | D-16-06006 | 12/22/2016 | 9.60 |
| Idaho | Avista Corp. | AVA | C-AVU-E-16-03 | 12/28/2016 | 9.50 |

| State | Utility | Parent Company Ticker | Case Identification | Date Authorized | Authorized ROE |
|---|---|---|---|---|---|
| Wyoming | MDU Resources Group Inc. | MDU | D-2004-117-ER-16 | 1/18/2017 | 9.45 |
| Michigan | DTE Electric Co. | DTE | C-U-18014 | 1/31/2017 | 10.10 |
| Arizona | Tucson Electric Power Co. | FTS | D-E-01933A-15-0322 | 2/24/2017 | 9.75 |
| Michigan | Consumers Energy Co. | CMS | C-U-17990 | 2/28/2017 | 10.10 |
| Minnesota | Otter Tail Power Co. | OTTR | D-E-017/GR-15-1033 | 3/2/2017 | 9.41 |
| Oklahoma | Oklahoma Gas and Electric Co. | OGE | Ca-PUD201500273 | 3/20/2017 | 9.50 |
| Florida | Gulf Power Co. | SO | D-160186-EI | 4/4/2017 | 10.25 |
| Missouri | Kansas City Power & Light | GXP | C-ER-2016-0285 | 5/3/2017 | 9.50 |
| Minnesota | Northern States Power Co. - MN | XEL | D-E-002/GR-15-826 | 5/11/2017 | 9.20 |
| Arkansas | Oklahoma Gas and Electric Co. | OGE | D-16-052-U | 5/18/2017 | 9.50 |
| North Dakota | MDU Resources Group Inc. | MDU | C-PU-16-666 | 6/16/2017 | 9.65 |
| Kentucky | Kentucky Utilities Co. | PPL | C-2016-00370 | 6/22/2017 | 9.70 |
| Kentucky | Louisville Gas & Electric Co. | PPL | C-2016-00371 (elec.) | 6/22/2017 | 9.70 |
| Arizona | Arizona Public Service Co. | PNW | D-E-01345A-16-0036 | 8/15/2017 | 10.00 |
| California | San Diego Gas & Electric Co. | SRE | Advice No. 3120-E | 10/26/2017 | 10.20 |
| California | Pacific Gas and Electric Co. | PCG | Advise No. 3887-G/5148-E | 10/26/2017 | 10.25 |
| California | Southern California Edison Co. | EIX | Advice No. 3665-E | 10/26/2017 | 10.30 |
| Florida | Tampa Electric Co. | EMA | D-20170210-EI | 11/6/2017 | 10.25 |
| Alaska | Alaska Electric Light Power | AVA | D-U-16-086 | 11/15/2017 | 11.95 |
| Washington | Puget Sound Energy Inc. | | D-UE-170033 | 12/5/2017 | 9.50 |
| Wisconsin | Northern States Power Co - WI | XEL | D-4220-UR-123 (Elec) | 12/7/2017 | 9.80 |
| Texas | Southwestern Electric Power Co | AEP | D-46449 | 12/14/2017 | 9.60 |
| Texas | El Paso Electric Co. | EE | D-46831 | 12/14/2017 | 9.65 |
| Oregon | Portland General Electric Co. | POR | D-UE-319 | 12/18/2017 | 9.50 |
| New Mexico | Public Service Co. of NM | PNM | C-16-00276-UT | 12/20/2017 | 9.58 |
| Vermont | Green Mountain Power Corp. | | C-17-3112-INV | 12/21/2017 | 9.10 |
| Idaho | Avista Corp. | AVA | D-AVU-E-17-01 | 12/28/2017 | 9.50 |
| Nevada | Nevada Power Co. | BRK.A | D-17-06003 | 12/29/2017 | 9.51 |
| Kentucky | Kentucky Power Co. | AEP | C-2017-00179 | 1/18/2018 | 9.70 |
| Oklahoma | Public Service Co. of OK | AEP | Ca-PUD201700151 | 1/31/2018 | 9.30 |
| Iowa | Interstate Power & Light Co. | LNT | D-RPU-2017-0001 | 2/2/2018 | 9.98 |
| North Carolina | Duke Energy Progress LLC | DUK | D-E-2, Sub 1142 | 2/23/2018 | 9.90 |
| Minnesota | ALLETE (Minnesota Power) | ALE | D-E-015/GR-16-664 | 3/12/2018 | 9.25 |
| Michigan | Consumers Energy Co. | CMS | C-U-18322 | 3/29/2018 | 10.00 |
| Michigan | Indiana Michigan Power Co. | AEP | C-U-18370 | 4/12/2018 | 9.90 |
| Kentucky | Duke Energy Kentucky Inc. | DUK | C-2017-00321 | 4/13/2018 | 9.73 |
| Michigan | DTE Electric Co. | DTE | C-U-18255 | 4/18/2018 | 10.00 |
| Washington | Avista Corp. | AVA | D-UE-170485 | 4/26/2018 | 9.50 |
| Indiana | Indiana Michigan Power Co. | AEP | Ca-44967 | 5/30/2018 | 9.95 |
| Hawaii | Hawaiian Electric Co. | HE | D-2016-0328 | 6/22/2018 | 9.50 |
| North Carolina | Duke Energy Carolinas LLC | DUK | D-E-7, Sub 1146 | 6/22/2018 | 9.90 |
| Hawaii | Hawaii Electric Light Co | HE | D-2015-0170 | 6/29/2018 | 9.50 |
| New Mexico | Southwestern Public Service Co | XEL | C-17-00255-UT | 9/5/2018 | 9.56 |
| Wisconsin | Wisconsin Power and Light Co | LNT | D-6680-UR-121 (Elec) | 9/14/2018 | 10.00 |
| Wisconsin | Madison Gas and Electric Co. | MGEE | D-3270-UR-122 (Elec) | 9/20/2018 | 9.80 |
| North Dakota | Otter Tail Power Co. | OTTR | C-PU-17-398 | 9/26/2018 | 9.77 |
| Kansas | Evergy Kansas Central Inc. | EVRG | D-18-WSEE-328-RTS | 9/27/2018 | 9.30 |
| Indiana | Indianapolis Power & Light Co. | AES | Ca-45029 | 10/31/2018 | 9.99 |
| Kansas | Evergy Metro Inc | EVRG | D-18-KCPE-480-RTS | 12/13/2018 | 9.30 |
| Oregon | Portland General Electric Co. | POR | D-UE-335 | 12/14/2018 | 9.50 |
| Vermont | Green Mountain Power Corp. | | C-18-0974-TF | 12/21/2018 | 9.30 |

| State | Utility | Parent Company Ticker | Case Identification | Date Authorized | Authorized ROE |
|---|---|---|---|---|---|
| Michigan | Consumers Energy Co. | CMS | C-U-20134 | 1/9/2019 | 10.00 |
| West Virginia | Appalachian Power Co. | AEP | C-18-0646-E-42T | 2/27/2019 | 9.75 |
| Oklahoma | Public Service Co. of OK | AEP | Ca-PUD201800097 | 3/14/2019 | 9.40 |
| Kentucky | Kentucky Utilities Co. | PPL | C-2018-00294 | 4/30/2019 | 9.73 |
| Kentucky | Louisville Gas & Electric Co. | PPL | C-2018-00295 (elec.) | 4/30/2019 | 9.73 |
| South Carolina | Duke Energy Carolinas LLC | DUK | D-2018-319-E | 5/1/2019 | 9.50 |
| Michigan | DTE Electric Co. | DTE | C-U-20162 | 5/2/2019 | 10.00 |
| South Carolina | Duke Energy Progress LLC | DUK | D-2018-318-E | 5/8/2019 | 9.50 |
| South Dakota | Otter Tail Power Co. | OTTR | D-EL18-021 | 5/14/2019 | 8.75 |
| Hawaii | Maui Electric Company Ltd | HE | D-2017-0150 | 5/16/2019 | 9.50 |
| Michigan | Upper Peninsula Power Co. | | C-U-20276 | 5/23/2019 | 9.90 |
| Vermont | Green Mountain Power Corp. | | C-19-1932-TF | 8/29/2019 | 9.06 |
| Wisconsin | Northern States Power Co - WI | XEL | D- 4220-UR-124 (Elec) | 9/4/2019 | 10.00 |
| Wisconsin | Wisconsin Electric Power Co. | WEC | D-05-UR-109 (WEP-Elec) | 10/31/2019 | 10.00 |
| Wisconsin | Wisconsin Public Service Corp. | WEC | D-6690-UR-126 (Elec) | 10/31/2019 | 10.00 |
| Louisiana | Entergy New Orleans LLC | ETR | D-UD-18-07 (elec.) | 11/7/2019 | 9.35 |
| Idaho | Avista Corp. | AVA | C-AVU-E-1904 | 11/29/2019 | 9.50 |
| Indiana | Northern IN Public Svc Co. | NI | Ca-45159 | 12/4/2019 | 9.75 |
| Georgia | Georgia Power Co. | SO | D-42516 | 12/17/2019 | 10.50 |
| California | San Diego Gas & Electric Co. | SRE | A-19-04-017 (Elec) | 12/19/2019 | 10.20 |
| California | Pacific Gas and Electric Co. | PCG | A-19-04-015 | 12/19/2019 | 10.25 |
| California | Southern California Edison Co. | EIX | A-19-04-014 | 12/19/2019 | 10.30 |
| Arkansas | Southwestern Electric Power Co | AEP | D-19-008-U | 12/20/2019 | 9.45 |
| Montana | NorthWestern Corp. | NWE | D2018.2.12 | 12/20/2019 | 9.65 |
| Nevada | Sierra Pacific Power Co. | BRK.A | D-19-06002 | 12/24/2019 | 9.50 |
| Iowa | Interstate Power & Light Co. | LNT | D-RPU-2019-0001 | 1/8/2020 | 10.02 |
| Michigan | Indiana Michigan Power Co. | AEP | C-U-20359 | 1/23/2020 | 9.86 |
| California | PacifiCorp | BRK.A | A-18-04-002 | 2/6/2020 | 10.00 |
| Colorado | Public Service Co. of CO | XEL | D-19AL-0268E | 2/11/2020 | 9.30 |
| North Carolina | Virginia Electric & Power Co. | D | E-22, Sub 562 | 2/24/2020 | 9.75 |
| Indiana | Indiana Michigan Power Co. | AEP | Ca-45235 | 3/11/2020 | 9.70 |
| Washington | Avista Corp. | AVA | D-UE-190334 | 3/25/2020 | 9.40 |

| | |
|---|---|
| Average | 9.75 |
| Median | 9.71 |
| Minimum | 8.75 |
| Maximum | 11.95 |
| Count >=10% 2017-2020 | 23 |
| Count >=10% 2019-2020 | 11 |
| 2019-2020 Average | 9.73 |
| 2019-2020 Median | 9.74 |

Source: Regulatory Research Associates

Alternative Bond Yield Plus Risk Premium Analyses

| [1] Constant | [2] LN(30-Year Treasury) | [3] VIX |
|---|---|---|
| -0.0275 | -0.0258 | 0.0003 |

| | 30-Yr. Treasury Yield [4] | VIX [5] | Risk Premium [6] | Return on Equity [7] |
|---|---|---|---|---|
| Current 30-Year Treasury | 1.37% | 50.00 | 9.73% | 11.10% |
| Near-Term Projected 30-Year Treasury | 1.75% | 50.00 | 9.10% | 10.85% |
| Long-Term Projected 30-Year Treasury | 3.45% | 50.00 | 7.35% | 10.80% |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.877892 |
| R Square | 0.770695 |
| Adjusted R Square | 0.770166 |
| Standard Error | 0.005267 |
| Observations | 870 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 2 | 0.080823365 | 0.04041168 | 1456.993126 | 5.4887E-278 |
| Residual | 867 | 0.024047422 | 2.7736E-05 | | |
| Total | 869 | 0.104870787 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | -0.027508 | 0.001634589 | -16.828393 | 3.33048E-55 | -0.03071572 | -0.024299289 |
| LN(30-Year Treasury) | -0.02576 | 0.000480454 | -53.615831 | 1.5773E-277 | -0.02670294 | -0.024816963 |
| VIX | 0.000286 | 2.91346E-05 | 9.82722569 | 1.1091E-21 | 0.00022913 | 0.000343495 |

Notes:
[1] Constant of regression equation (1990 - 2020)
[2] Equals Regression Coefficient of 30-year Treasury Yield variable
[3] Equals Regression Coefficient of VIX variable
[4] Source: Current = Bloomberg Professional, Rebuttal Exhibit DWD-5.
Near-Term = Blue Chip Financial Forecasts, Vol. 39, No. 4, April 1, 2020, at 2
Long-Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2018, at 14
[5] Source: Testimony of J. Randall Woolridge, at 25
[6] Equals [1] + (ln([4]) x [2]) + ([3] x [5])
[7] Equals [4] + [6]
[8] Source: S&P Global Market Intelligence, Regulatory Research Associates
[9] Source: S&P Global Market Intelligence, Regulatory Research Associates
[10] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[11] Equals LN[10]
[12] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[13] Equals [9] - [10]

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 10/19/1990 | 13.00% | 8.67% | -2.45 | 22.69 | 4.33% |
| 10/25/1990 | 12.30% | 8.68% | -2.44 | 22.80 | 3.62% |
| 11/21/1990 | 12.70% | 8.69% | -2.44 | 22.98 | 4.01% |
| 12/13/1990 | 12.30% | 8.67% | -2.44 | 22.97 | 3.63% |
| 12/17/1990 | 12.87% | 8.67% | -2.45 | 23.00 | 4.20% |
| 12/18/1990 | 13.10% | 8.67% | -2.45 | 23.02 | 4.43% |
| 12/19/1990 | 12.00% | 8.66% | -2.45 | 23.04 | 3.34% |
| 12/20/1990 | 12.75% | 8.66% | -2.45 | 23.05 | 4.09% |
| 12/21/1990 | 12.50% | 8.66% | -2.45 | 23.07 | 3.84% |
| 12/27/1990 | 12.79% | 8.66% | -2.45 | 23.13 | 4.13% |
| 1/2/1991 | 13.10% | 8.66% | -2.45 | 23.25 | 4.44% |
| 1/4/1991 | 12.50% | 8.65% | -2.45 | 23.31 | 3.85% |
| 1/15/1991 | 12.75% | 8.65% | -2.45 | 23.75 | 4.10% |
| 1/25/1991 | 11.70% | 8.63% | -2.45 | 23.94 | 3.07% |
| 2/4/1991 | 12.50% | 8.60% | -2.45 | 23.92 | 3.90% |
| 2/7/1991 | 12.50% | 8.59% | -2.45 | 23.95 | 3.91% |
| 2/12/1991 | 13.00% | 8.57% | -2.46 | 23.99 | 4.43% |
| 2/14/1991 | 12.72% | 8.56% | -2.46 | 24.02 | 4.16% |
| 2/22/1991 | 12.80% | 8.55% | -2.46 | 24.08 | 4.25% |
| 3/6/1991 | 13.10% | 8.53% | -2.46 | 24.18 | 4.57% |
| 3/8/1991 | 12.30% | 8.52% | -2.46 | 24.21 | 3.78% |
| 3/8/1991 | 13.00% | 8.52% | -2.46 | 24.21 | 4.48% |
| 4/22/1991 | 13.00% | 8.49% | -2.47 | 24.23 | 4.51% |
| 5/7/1991 | 13.50% | 8.47% | -2.47 | 24.22 | 5.03% |
| 5/13/1991 | 13.25% | 8.47% | -2.47 | 24.15 | 4.78% |
| 5/30/1991 | 12.75% | 8.43% | -2.47 | 23.59 | 4.32% |
| 6/12/1991 | 12.00% | 8.41% | -2.48 | 23.03 | 3.59% |
| 6/25/1991 | 11.70% | 8.38% | -2.48 | 22.47 | 3.32% |
| 6/28/1991 | 12.50% | 8.38% | -2.48 | 22.31 | 4.12% |
| 7/1/1991 | 12.00% | 8.37% | -2.48 | 22.25 | 3.63% |
| 7/3/1991 | 12.50% | 8.36% | -2.48 | 22.15 | 4.14% |
| 7/19/1991 | 12.10% | 8.34% | -2.48 | 21.55 | 3.76% |
| 8/1/1991 | 12.90% | 8.32% | -2.49 | 20.89 | 4.58% |
| 8/16/1991 | 13.20% | 8.29% | -2.49 | 20.12 | 4.91% |
| 9/27/1991 | 12.50% | 8.23% | -2.50 | 19.02 | 4.27% |
| 9/30/1991 | 12.25% | 8.23% | -2.50 | 18.99 | 4.02% |
| 10/17/1991 | 13.00% | 8.20% | -2.50 | 18.47 | 4.80% |
| 10/23/1991 | 12.50% | 8.20% | -2.50 | 18.20 | 4.30% |
| 10/23/1991 | 12.55% | 8.20% | -2.50 | 18.20 | 4.35% |
| 10/31/1991 | 11.80% | 8.19% | -2.50 | 17.68 | 3.61% |
| 11/1/1991 | 12.00% | 8.19% | -2.50 | 17.63 | 3.81% |
| 11/5/1991 | 12.25% | 8.19% | -2.50 | 17.55 | 4.06% |
| 11/12/1991 | 12.50% | 8.18% | -2.50 | 17.35 | 4.32% |
| 11/12/1991 | 13.25% | 8.18% | -2.50 | 17.35 | 5.07% |
| 11/25/1991 | 12.40% | 8.18% | -2.50 | 17.21 | 4.22% |
| 11/26/1991 | 11.60% | 8.18% | -2.50 | 17.20 | 3.42% |
| 11/26/1991 | 12.50% | 8.18% | -2.50 | 17.20 | 4.32% |
| 11/27/1991 | 12.10% | 8.18% | -2.50 | 17.19 | 3.92% |
| 12/18/1991 | 12.25% | 8.15% | -2.51 | 17.07 | 4.10% |
| 12/19/1991 | 12.60% | 8.15% | -2.51 | 17.06 | 4.45% |
| 12/19/1991 | 12.80% | 8.15% | -2.51 | 17.06 | 4.65% |
| 12/20/1991 | 12.65% | 8.14% | -2.51 | 17.04 | 4.51% |
| 1/9/1992 | 12.80% | 8.09% | -2.51 | 17.13 | 4.71% |
| 1/16/1992 | 12.75% | 8.07% | -2.52 | 17.14 | 4.68% |
| 1/21/1992 | 12.00% | 8.06% | -2.52 | 17.12 | 3.94% |
| 1/22/1992 | 13.00% | 8.06% | -2.52 | 17.10 | 4.94% |
| 1/27/1992 | 12.65% | 8.05% | -2.52 | 17.09 | 4.60% |
| 1/31/1992 | 12.00% | 8.04% | -2.52 | 17.12 | 3.96% |
| 2/11/1992 | 12.40% | 8.03% | -2.52 | 17.16 | 4.37% |
| 2/25/1992 | 12.50% | 8.01% | -2.52 | 17.14 | 4.49% |
| 3/16/1992 | 11.43% | 7.98% | -2.53 | 17.25 | 3.45% |
| 3/18/1992 | 12.28% | 7.98% | -2.53 | 17.26 | 4.30% |
| 4/2/1992 | 12.10% | 7.95% | -2.53 | 17.24 | 4.15% |
| 4/9/1992 | 11.45% | 7.93% | -2.53 | 17.24 | 3.52% |
| 4/10/1992 | 11.50% | 7.93% | -2.53 | 17.23 | 3.57% |
| 4/14/1992 | 11.50% | 7.92% | -2.54 | 17.21 | 3.58% |
| 5/5/1992 | 11.50% | 7.89% | -2.54 | 17.08 | 3.61% |
| 5/12/1992 | 11.87% | 7.88% | -2.54 | 17.09 | 3.99% |
| 5/12/1992 | 12.46% | 7.88% | -2.54 | 17.09 | 4.58% |
| 6/1/1992 | 12.30% | 7.86% | -2.54 | 17.02 | 4.44% |
| 6/12/1992 | 10.90% | 7.85% | -2.54 | 16.97 | 3.05% |
| 6/26/1992 | 12.35% | 7.85% | -2.54 | 16.91 | 4.50% |
| 6/29/1992 | 11.00% | 7.85% | -2.55 | 16.88 | 3.15% |
| 6/30/1992 | 13.00% | 7.85% | -2.55 | 16.86 | 5.15% |
| 7/13/1992 | 11.90% | 7.84% | -2.55 | 16.78 | 4.06% |
| 7/13/1992 | 13.50% | 7.84% | -2.55 | 16.78 | 5.66% |
| 7/22/1992 | 11.20% | 7.83% | -2.55 | 16.65 | 3.37% |
| 8/3/1992 | 12.00% | 7.81% | -2.55 | 16.52 | 4.19% |
| 8/6/1992 | 12.50% | 7.80% | -2.55 | 16.48 | 4.70% |
| 9/22/1992 | 12.00% | 7.71% | -2.56 | 15.88 | 4.29% |
| 9/28/1992 | 11.40% | 7.71% | -2.56 | 15.78 | 3.69% |
| 9/30/1992 | 11.75% | 7.71% | -2.56 | 15.75 | 4.04% |
| 10/2/1992 | 13.00% | 7.70% | -2.56 | 15.74 | 5.30% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 10/12/1992 | 12.20% | 7.70% | -2.56 | 15.85 | 4.50% |
| 10/16/1992 | 13.16% | 7.71% | -2.56 | 15.82 | 5.45% |
| 10/30/1992 | 11.75% | 7.71% | -2.56 | 15.75 | 4.04% |
| 11/3/1992 | 12.00% | 7.71% | -2.56 | 15.74 | 4.29% |
| 12/3/1992 | 11.85% | 7.68% | -2.57 | 15.36 | 4.17% |
| 12/15/1992 | 11.00% | 7.66% | -2.57 | 15.17 | 3.34% |
| 12/16/1992 | 11.90% | 7.66% | -2.57 | 15.14 | 4.24% |
| 12/16/1992 | 12.40% | 7.66% | -2.57 | 15.14 | 4.74% |
| 12/17/1992 | 12.00% | 7.66% | -2.57 | 15.10 | 4.34% |
| 12/22/1992 | 12.30% | 7.65% | -2.57 | 14.99 | 4.65% |
| 12/22/1992 | 12.40% | 7.65% | -2.57 | 14.99 | 4.75% |
| 12/29/1992 | 12.25% | 7.63% | -2.57 | 14.86 | 4.62% |
| 12/30/1992 | 12.00% | 7.63% | -2.57 | 14.84 | 4.37% |
| 12/31/1992 | 11.90% | 7.62% | -2.57 | 14.82 | 4.28% |
| 1/12/1993 | 12.00% | 7.61% | -2.58 | 14.72 | 4.39% |
| 1/21/1993 | 11.25% | 7.59% | -2.58 | 14.52 | 3.66% |
| 2/2/1993 | 11.40% | 7.56% | -2.58 | 14.35 | 3.84% |
| 2/15/1993 | 12.30% | 7.52% | -2.59 | 14.26 | 4.78% |
| 2/24/1993 | 11.90% | 7.49% | -2.59 | 14.18 | 4.41% |
| 2/26/1993 | 11.80% | 7.48% | -2.59 | 14.16 | 4.32% |
| 2/26/1993 | 12.20% | 7.48% | -2.59 | 14.16 | 4.72% |
| 4/23/1993 | 11.75% | 7.29% | -2.62 | 13.85 | 4.46% |
| 5/11/1993 | 11.75% | 7.24% | -2.62 | 13.86 | 4.51% |
| 5/14/1993 | 11.50% | 7.24% | -2.63 | 13.87 | 4.26% |
| 5/25/1993 | 11.50% | 7.22% | -2.63 | 13.87 | 4.28% |
| 5/28/1993 | 11.00% | 7.22% | -2.63 | 13.84 | 3.78% |
| 6/3/1993 | 12.00% | 7.21% | -2.63 | 13.83 | 4.79% |
| 6/16/1993 | 11.50% | 7.19% | -2.63 | 13.77 | 4.31% |
| 6/18/1993 | 12.10% | 7.18% | -2.63 | 13.77 | 4.92% |
| 6/25/1993 | 11.67% | 7.17% | -2.64 | 13.74 | 4.50% |
| 7/21/1993 | 11.38% | 7.10% | -2.65 | 13.42 | 4.28% |
| 7/23/1993 | 10.46% | 7.09% | -2.65 | 13.34 | 3.37% |
| 8/24/1993 | 11.50% | 6.95% | -2.67 | 12.79 | 4.55% |
| 9/21/1993 | 10.50% | 6.80% | -2.69 | 12.72 | 3.70% |
| 9/29/1993 | 11.47% | 6.76% | -2.69 | 12.73 | 4.71% |
| 9/30/1993 | 11.60% | 6.76% | -2.69 | 12.74 | 4.84% |
| 11/2/1993 | 10.80% | 6.60% | -2.72 | 12.67 | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | -2.72 | 12.76 | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | -2.73 | 12.85 | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | -2.74 | 12.75 | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | -2.74 | 12.72 | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | -2.74 | 12.66 | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | -2.74 | 12.49 | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | -2.75 | 12.45 | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | -2.75 | 12.39 | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | -2.75 | 12.37 | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | -2.75 | 12.34 | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | -2.76 | 12.38 | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | -2.76 | 12.39 | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | -2.76 | 12.39 | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | -2.76 | 12.40 | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | -2.76 | 12.43 | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | -2.75 | 13.03 | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | -2.74 | 13.20 | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | -2.74 | 13.25 | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | -2.73 | 13.32 | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | -2.71 | 13.42 | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | -2.68 | 13.42 | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | -2.61 | 13.77 | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | -2.60 | 13.94 | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | -2.60 | 13.94 | 3.45% |
| 11/18/1994 | 11.20% | 7.46% | -2.60 | 14.12 | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | -2.59 | 14.14 | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | -2.59 | 14.20 | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | -2.58 | 14.29 | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | -2.58 | 14.29 | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | -2.58 | 14.28 | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | -2.58 | 14.26 | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | -2.58 | 14.24 | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | -2.58 | 14.14 | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | -2.57 | 14.14 | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | -2.57 | 13.71 | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | -2.56 | 13.56 | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | -2.56 | 13.49 | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | -2.56 | 13.37 | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | -2.56 | 13.35 | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | -2.56 | 13.32 | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | -2.56 | 13.31 | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | -2.56 | 13.30 | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | -2.56 | 13.28 | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | -2.56 | 13.20 | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | -2.57 | 13.21 | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | -2.57 | 13.22 | 3.55% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 6/9/1995 | 11.25% | 7.60% | -2.58 | 13.26 | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | -2.58 | 13.24 | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | -2.59 | 13.20 | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | -2.63 | 12.48 | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | -2.64 | 12.24 | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | -2.64 | 12.24 | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | -2.64 | 12.24 | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | -2.64 | 12.24 | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | -2.67 | 12.47 | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | -2.67 | 12.47 | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | -2.68 | 12.51 | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | -2.69 | 12.52 | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | -2.70 | 12.52 | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | -2.70 | 12.50 | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | -2.71 | 12.48 | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | -2.74 | 12.63 | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | -2.75 | 13.49 | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | -2.75 | 13.63 | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | -2.74 | 13.74 | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | -2.74 | 13.74 | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | -2.74 | 13.93 | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | -2.74 | 13.99 | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | -2.74 | 14.15 | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | -2.74 | 14.24 | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | -2.74 | 14.73 | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | -2.74 | 14.77 | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | -2.72 | 15.35 | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | -2.70 | 15.98 | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | -2.69 | 16.22 | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | -2.69 | 16.44 | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | -2.68 | 16.58 | 4.47% |
| 12/18/1996 | 11.75% | 6.84% | -2.68 | 16.80 | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | -2.68 | 16.84 | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | -2.68 | 16.85 | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | -2.68 | 17.23 | 4.98% |
| 2/20/1997 | 11.80% | 6.82% | -2.69 | 17.29 | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | -2.69 | 17.83 | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | -2.69 | 17.86 | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | -2.69 | 18.20 | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | -2.69 | 18.20 | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | -2.69 | 19.04 | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | -2.72 | 22.58 | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | -2.72 | 22.85 | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | -2.75 | 23.45 | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | -2.77 | 23.41 | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | -2.77 | 23.39 | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | -2.78 | 23.36 | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | -2.79 | 23.68 | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | -2.82 | 23.14 | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | -2.85 | 23.80 | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | -2.89 | 26.06 | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | -2.89 | 26.34 | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | -2.90 | 26.58 | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | -2.92 | 27.54 | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | -2.93 | 28.19 | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | -2.93 | 28.47 | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | -2.90 | 25.77 | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | -2.86 | 24.95 | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | -2.83 | 24.31 | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | -2.81 | 23.49 | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | -2.81 | 23.49 | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | -2.78 | 23.35 | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | -2.78 | 22.96 | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | -2.78 | 23.84 | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | -2.79 | 23.36 | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | -2.81 | 22.44 | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | -2.83 | 22.97 | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | -2.83 | 23.03 | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | -2.85 | 23.49 | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | -2.85 | 23.15 | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | -2.88 | 24.39 | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | -2.88 | 24.93 | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | -2.88 | 25.07 | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | -2.88 | 25.07 | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | -2.88 | 24.96 | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | -2.89 | 24.49 | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | -2.89 | 24.53 | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | -2.89 | 24.55 | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | -2.89 | 24.84 | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | -2.89 | 25.69 | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | -2.90 | 26.17 | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | -2.90 | 26.22 | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | -2.90 | 26.14 | 7.00% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 1/22/2002 | 10.00% | 5.50% | -2.90 | 25.49 | 4.50% |
| 3/27/2002 | 10.10% | 5.45% | -2.91 | 24.65 | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | -2.91 | 24.49 | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | -2.91 | 24.29 | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | -2.91 | 24.33 | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | -2.90 | 24.42 | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | -2.90 | 24.46 | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | -2.90 | 24.46 | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | -2.90 | 24.08 | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | -2.91 | 25.15 | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | -2.92 | 25.82 | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | -2.94 | 28.03 | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | -2.94 | 28.29 | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | -2.95 | 28.48 | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | -2.96 | 28.93 | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | -2.97 | 29.66 | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | -2.99 | 30.74 | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | -2.99 | 30.99 | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | -2.99 | 31.04 | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | -3.00 | 31.54 | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | -3.00 | 31.74 | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | -3.01 | 31.70 | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | -3.04 | 28.27 | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | -3.04 | 28.19 | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | -3.04 | 27.44 | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | -3.04 | 26.97 | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | -3.04 | 26.27 | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | -3.03 | 24.78 | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | -3.01 | 20.47 | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | -3.01 | 20.47 | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | -3.01 | 20.40 | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | -3.01 | 20.31 | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | -3.01 | 20.31 | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | -3.01 | 20.15 | 5.56% |
| 1/13/2004 | 12.00% | 4.95% | -3.01 | 19.31 | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | -3.00 | 18.17 | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | -2.99 | 17.96 | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | -2.99 | 17.85 | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | -2.98 | 17.43 | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | -2.98 | 17.36 | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | -2.98 | 17.33 | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | -2.98 | 17.30 | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | -2.98 | 16.96 | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | -2.98 | 16.96 | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | -2.97 | 16.69 | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | -2.98 | 16.53 | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | -2.98 | 16.35 | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | -2.98 | 15.94 | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | -2.98 | 15.75 | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | -2.98 | 15.59 | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | -2.98 | 15.51 | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | -2.98 | 15.51 | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | -2.98 | 15.47 | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | -2.98 | 15.47 | 6.43% |
| 12/29/2004 | 9.85% | 5.08% | -2.98 | 15.30 | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | -2.98 | 15.12 | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | -3.00 | 14.59 | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | -3.00 | 14.46 | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | -3.01 | 14.18 | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | -3.02 | 14.05 | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | -3.02 | 14.02 | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | -3.02 | 14.00 | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | -3.04 | 13.89 | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | -3.04 | 13.75 | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | -3.04 | 13.71 | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | -3.05 | 13.64 | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | -3.07 | 13.17 | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | -3.07 | 12.94 | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | -3.08 | 12.84 | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | -3.09 | 12.77 | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | -3.09 | 12.78 | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | -3.09 | 12.97 | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | -3.09 | 12.96 | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | -3.09 | 12.91 | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | -3.09 | 12.91 | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | -3.09 | 12.90 | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | -3.09 | 12.90 | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | -3.09 | 12.87 | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | -3.09 | 12.87 | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | -3.09 | 12.82 | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | -3.10 | 12.72 | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | -3.09 | 12.39 | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | -3.08 | 12.34 | 5.58% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 4/26/2006 | 10.60% | 4.64% | -3.07 | 12.34 | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | -3.06 | 12.47 | 6.91% |
| 6/6/2006 | 10.00% | 4.75% | -3.05 | 12.72 | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | -3.04 | 13.07 | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | -3.03 | 13.12 | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | -3.02 | 13.29 | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | -3.02 | 13.29 | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | -3.02 | 13.27 | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | -3.02 | 13.20 | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | -3.02 | 13.19 | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | -3.01 | 13.25 | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | -3.01 | 13.30 | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | -3.01 | 13.12 | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | -3.01 | 13.12 | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | -3.01 | 13.12 | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | -3.00 | 13.07 | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | -3.00 | 13.07 | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | -3.00 | 13.06 | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | -3.00 | 12.98 | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | -3.00 | 12.98 | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | -3.00 | 12.98 | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | -3.01 | 12.98 | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | -3.01 | 12.98 | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | -3.01 | 12.98 | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | -3.01 | 12.98 | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | -3.01 | 12.98 | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | -3.01 | 12.97 | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | -3.01 | 12.96 | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | -3.02 | 12.81 | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | -3.02 | 12.78 | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | -3.04 | 12.22 | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | -3.04 | 12.21 | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | -3.04 | 12.21 | 5.45% |
| 5/22/2007 | 10.20% | 4.80% | -3.04 | 12.19 | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | -3.04 | 12.19 | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | -3.04 | 12.18 | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | -3.04 | 12.16 | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | -3.03 | 12.27 | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | -3.03 | 12.30 | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | -3.03 | 12.31 | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | -3.03 | 12.38 | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | -3.02 | 12.56 | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | -3.02 | 12.65 | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | -3.02 | 12.65 | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | -3.02 | 13.76 | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | -3.01 | 15.94 | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | -3.01 | 16.15 | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | -3.02 | 16.62 | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | -3.02 | 18.14 | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | -3.02 | 18.45 | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | -3.02 | 18.60 | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | -3.02 | 18.62 | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | -3.02 | 18.62 | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | -3.02 | 18.74 | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | -3.03 | 18.77 | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | -3.03 | 18.77 | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | -3.03 | 18.84 | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | -3.03 | 18.88 | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | -3.03 | 19.16 | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | -3.03 | 19.51 | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | -3.04 | 19.99 | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | -3.04 | 20.14 | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | -3.04 | 20.21 | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | -3.05 | 21.45 | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | -3.05 | 21.99 | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | -3.06 | 22.55 | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | -3.08 | 23.32 | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | -3.08 | 23.35 | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | -3.08 | 23.46 | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | -3.09 | 23.32 | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | -3.09 | 23.18 | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | -3.09 | 22.89 | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | -3.09 | 22.73 | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | -3.09 | 22.73 | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | -3.10 | 22.88 | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | -3.10 | 23.08 | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | -3.10 | 23.33 | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | -3.10 | 23.34 | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | -3.10 | 23.37 | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | -3.10 | 23.23 | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | -3.10 | 23.01 | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | -3.11 | 23.46 | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | -3.11 | 23.46 | 6.17% |

| [8]<br>Date of Electric Rate Case | [9]<br>Return on Equity (%) | [10]<br>30 Year Treasury (%) | [11]<br>LN(30-Year Treasury) | [12]<br>VIX | [13]<br>Risk Premium |
|---|---|---|---|---|---|
| 9/24/2008 | 10.65% | 4.48% | -3.11 | 23.46 | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | -3.11 | 23.77 | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | -3.11 | 24.61 | 5.69% |
| 11/13/2008 | 10.55% | 4.45% | -3.11 | 29.58 | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | -3.11 | 29.98 | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | -3.12 | 31.79 | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | -3.15 | 34.13 | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | -3.16 | 34.34 | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | -3.16 | 34.34 | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | -3.17 | 34.47 | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | -3.18 | 35.25 | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | -3.19 | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | -3.19 | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | -3.19 | 35.81 | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | -3.20 | 36.26 | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | -3.20 | 36.58 | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | -3.20 | 36.94 | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | -3.23 | 39.59 | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | -3.24 | 40.42 | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | -3.26 | 42.04 | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | -3.27 | 42.91 | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | -3.27 | 43.10 | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | -3.28 | 43.29 | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | -3.28 | 43.40 | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | -3.29 | 43.96 | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | -3.29 | 44.24 | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | -3.28 | 45.01 | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | -3.28 | 45.06 | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | -3.28 | 44.95 | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | -3.28 | 44.55 | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | -3.27 | 38.96 | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | -3.21 | 33.90 | 6.68% |
| 10/23/2009 | 10.88% | 4.06% | -3.20 | 33.22 | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | -3.20 | 32.57 | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | -3.19 | 32.48 | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | -3.18 | 30.89 | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | -3.18 | 30.79 | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | -3.18 | 30.58 | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | -3.18 | 30.18 | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | -3.17 | 29.90 | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | -3.17 | 28.98 | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | -3.17 | 28.98 | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | -3.16 | 28.70 | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | -3.16 | 28.70 | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | -3.16 | 28.46 | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | -3.16 | 28.46 | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | -3.16 | 28.46 | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | -3.16 | 27.91 | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | -3.15 | 27.67 | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | -3.15 | 27.09 | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | -3.13 | 26.08 | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | -3.13 | 26.01 | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | -3.13 | 26.01 | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | -3.13 | 26.01 | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | -3.13 | 25.43 | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | -3.12 | 25.05 | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | -3.12 | 24.80 | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | -3.12 | 24.54 | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | -3.12 | 24.43 | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | -3.12 | 24.37 | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | -3.12 | 24.10 | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | -3.12 | 23.85 | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | -3.12 | 23.47 | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | -3.12 | 22.82 | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | -3.11 | 22.16 | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | -3.11 | 22.11 | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | -3.11 | 22.11 | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | -3.11 | 22.11 | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | -3.11 | 22.26 | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | -3.11 | 22.26 | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | -3.11 | 22.81 | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | -3.11 | 22.81 | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | -3.11 | 23.00 | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | -3.11 | 23.16 | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | -3.12 | 23.19 | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | -3.12 | 23.19 | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | -3.12 | 23.30 | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | -3.12 | 23.34 | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | -3.12 | 23.43 | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | -3.12 | 23.43 | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | -3.12 | 23.39 | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | -3.12 | 23.40 | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | -3.12 | 23.41 | 5.42% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 8/25/2010 | 9.90% | 4.37% | -3.13 | 23.38 | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | -3.14 | 23.44 | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | -3.14 | 23.46 | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | -3.14 | 23.44 | 5.68% |
| 9/16/2010 | 10.00% | 4.32% | -3.14 | 23.44 | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | -3.15 | 23.47 | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | -3.16 | 23.50 | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | -3.17 | 23.55 | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | -3.17 | 23.60 | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | -3.17 | 23.54 | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | -3.18 | 23.28 | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | -3.18 | 23.24 | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | -3.18 | 23.21 | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | -3.18 | 23.18 | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | -3.18 | 23.14 | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | -3.18 | 23.13 | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | -3.18 | 23.12 | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | -3.18 | 23.12 | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | -3.18 | 23.11 | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | -3.18 | 23.10 | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | -3.18 | 23.09 | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | -3.18 | 23.07 | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | -3.19 | 23.07 | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | -3.19 | 23.08 | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | -3.19 | 23.07 | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | -3.19 | 23.06 | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | -3.19 | 23.05 | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | -3.19 | 23.06 | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | -3.19 | 23.06 | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | -3.19 | 23.12 | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | -3.19 | 23.13 | 5.89% |
| 2/25/2011 | 10.00% | 4.14% | -3.18 | 22.58 | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | -3.18 | 21.29 | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | -3.17 | 21.16 | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | -3.17 | 20.69 | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | -3.16 | 20.17 | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | -3.16 | 20.13 | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | -3.16 | 20.08 | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | -3.16 | 19.84 | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | -3.16 | 19.84 | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | -3.15 | 19.44 | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | -3.15 | 19.02 | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | -3.14 | 18.83 | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | -3.14 | 18.83 | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | -3.13 | 18.48 | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | -3.13 | 18.46 | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | -3.13 | 18.77 | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | -3.13 | 19.05 | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | -3.13 | 19.13 | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | -3.13 | 19.53 | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | -3.14 | 20.31 | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | -3.16 | 21.34 | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | -3.19 | 22.82 | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | -3.19 | 23.27 | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | -3.25 | 25.28 | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | -3.25 | 25.28 | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | -3.27 | 25.67 | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | -3.27 | 25.67 | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | -3.28 | 25.76 | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | -3.28 | 25.76 | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | -3.28 | 25.77 | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | -3.28 | 25.77 | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | -3.29 | 25.76 | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | -3.33 | 25.89 | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | -3.34 | 25.91 | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | -3.36 | 26.12 | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | -3.37 | 26.14 | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | -3.37 | 26.15 | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | -3.38 | 26.16 | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | -3.41 | 25.99 | 7.06% |
| 4/4/2012 | 10.00% | 3.29% | -3.41 | 25.89 | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | -3.44 | 25.91 | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | -3.45 | 25.85 | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | -3.45 | 25.85 | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | -3.46 | 25.79 | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | -3.47 | 25.23 | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | -3.48 | 24.77 | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | -3.49 | 24.45 | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | -3.49 | 24.40 | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | -3.49 | 24.33 | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | -3.49 | 24.25 | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | -3.49 | 23.82 | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | -3.49 | 23.58 | 6.96% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 7/9/2012 | 10.20% | 3.03% | -3.50 | 23.14 | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | -3.50 | 22.59 | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | -3.50 | 22.07 | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | -3.50 | 22.07 | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | -3.53 | 19.11 | 6.86% |
| 9/19/2012 | 9.80% | 2.94% | -3.53 | 18.84 | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | -3.53 | 18.84 | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | -3.53 | 18.51 | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | -3.53 | 18.04 | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | -3.53 | 17.84 | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | -3.53 | 17.83 | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | -3.53 | 17.75 | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | -3.54 | 17.60 | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | -3.54 | 17.58 | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | -3.54 | 17.58 | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | -3.54 | 17.53 | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | -3.54 | 17.53 | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | -3.55 | 17.48 | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | -3.55 | 17.47 | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | -3.55 | 17.47 | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | -3.55 | 17.47 | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | -3.55 | 17.44 | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | -3.55 | 17.44 | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | -3.55 | 17.43 | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | -3.55 | 17.43 | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | -3.55 | 17.43 | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | -3.55 | 17.43 | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | -3.55 | 17.43 | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | -3.55 | 17.43 | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | -3.55 | 17.43 | 7.58% |
| 12/21/2012 | 10.20% | 2.87% | -3.55 | 17.43 | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | -3.55 | 17.45 | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | -3.56 | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | -3.56 | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | -3.56 | 17.50 | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | -3.56 | 17.45 | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | -3.56 | 17.45 | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | -3.56 | 17.01 | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | -3.56 | 16.89 | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | -3.56 | 16.85 | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | -3.55 | 16.34 | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | -3.54 | 15.87 | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | -3.53 | 15.25 | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | -3.52 | 15.02 | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | -3.51 | 14.87 | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | -3.51 | 14.89 | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | -3.51 | 14.95 | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | -3.50 | 14.99 | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | -3.50 | 15.02 | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | -3.48 | 15.06 | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | -3.46 | 14.82 | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | -3.45 | 14.72 | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | -3.42 | 14.56 | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | -3.42 | 14.56 | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | -3.41 | 14.46 | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | -3.40 | 14.45 | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | -3.38 | 14.40 | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | -3.37 | 14.36 | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | -3.37 | 14.36 | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | -3.36 | 14.38 | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | -3.36 | 14.38 | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | -3.36 | 14.38 | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | -3.36 | 14.34 | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | -3.36 | 14.34 | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | -3.35 | 14.34 | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | -3.35 | 14.35 | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | -3.35 | 14.35 | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | -3.35 | 14.35 | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | -3.35 | 14.37 | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | -3.35 | 14.37 | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | -3.35 | 14.37 | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | -3.35 | 14.37 | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | -3.35 | 14.38 | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | -3.34 | 14.41 | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | -3.30 | 14.62 | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | -3.30 | 14.65 | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | -3.29 | 14.72 | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | -3.29 | 14.66 | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | -3.29 | 14.66 | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | -3.29 | 14.58 | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | -3.30 | 14.38 | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | -3.30 | 14.35 | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | -3.30 | 14.26 | 6.73% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 6/30/2014 | 9.55% | 3.64% | -3.31 | 13.95 | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | -3.31 | 13.91 | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | -3.32 | 13.86 | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | -3.32 | 13.68 | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | -3.32 | 13.57 | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | -3.32 | 13.55 | 6.30% |
| 8/20/2014 | 9.75% | 3.56% | -3.33 | 13.61 | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | -3.34 | 13.59 | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | -3.34 | 13.57 | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | -3.35 | 13.57 | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | -3.35 | 13.57 | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | -3.37 | 13.62 | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | -3.39 | 14.09 | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | -3.39 | 14.09 | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | -3.40 | 13.94 | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | -3.40 | 13.82 | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | -3.40 | 13.82 | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | -3.41 | 13.78 | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | -3.41 | 13.80 | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | -3.41 | 13.80 | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | -3.42 | 13.83 | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | -3.42 | 13.86 | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | -3.42 | 13.96 | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | -3.42 | 13.98 | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | -3.46 | 14.37 | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | -3.49 | 14.67 | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | -3.51 | 14.90 | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | -3.52 | 14.96 | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | -3.52 | 14.98 | 6.77% |
| 4/23/2015 | 10.20% | 2.87% | -3.55 | 15.21 | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | -3.56 | 15.22 | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | -3.56 | 15.23 | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | -3.57 | 15.16 | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | -3.57 | 15.30 | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | -3.57 | 15.30 | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | -3.58 | 15.68 | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | -3.58 | 15.99 | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | -3.57 | 16.66 | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | -3.55 | 16.28 | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | -3.55 | 16.28 | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | -3.54 | 16.28 | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | -3.54 | 16.33 | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | -3.54 | 16.33 | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | -3.54 | 16.42 | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | -3.54 | 16.50 | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | -3.54 | 16.54 | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | -3.54 | 16.57 | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | -3.53 | 16.60 | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | -3.53 | 16.72 | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | -3.53 | 18.32 | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | -3.54 | 18.69 | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | -3.56 | 18.60 | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | -3.57 | 18.79 | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | -3.58 | 18.56 | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | -3.58 | 18.29 | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | -3.58 | 18.29 | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | -3.61 | 17.45 | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | -3.63 | 17.07 | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | -3.64 | 16.97 | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | -3.64 | 16.91 | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | -3.65 | 16.78 | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | -3.66 | 16.69 | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | -3.68 | 16.51 | 7.05% |
| 9/30/2016 | 9.90% | 2.53% | -3.68 | 16.46 | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | -3.70 | 15.63 | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | -3.70 | 15.60 | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | -3.69 | 15.49 | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | -3.69 | 15.34 | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | -3.69 | 14.95 | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | -3.68 | 14.87 | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | -3.68 | 14.76 | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | -3.68 | 14.76 | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | -3.68 | 14.72 | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | -3.68 | 14.62 | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | -3.68 | 14.58 | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | -3.67 | 14.50 | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | -3.67 | 14.50 | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | -3.67 | 14.40 | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | -3.67 | 14.40 | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | -3.67 | 14.34 | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | -3.66 | 14.20 | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | -3.65 | 14.12 | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | -3.65 | 14.05 | 7.50% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 2/15/2017 | 9.60% | 2.62% | -3.64 | 13.89 | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | -3.64 | 13.82 | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | -3.63 | 13.79 | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | -3.63 | 13.77 | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | -3.63 | 13.74 | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | -3.62 | 13.56 | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | -3.61 | 13.28 | 7.53% |
| 4/12/2017 | 9.40% | 2.74% | -3.60 | 13.06 | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | -3.59 | 13.05 | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | -3.58 | 12.95 | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | -3.57 | 12.88 | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | -3.56 | 12.88 | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | -3.56 | 12.87 | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | -3.54 | 12.69 | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | -3.54 | 12.66 | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | -3.54 | 12.66 | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | -3.52 | 12.24 | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | -3.52 | 11.95 | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | -3.53 | 11.47 | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | -3.53 | 11.42 | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | -3.54 | 11.23 | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | -3.54 | 11.22 | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | -3.54 | 11.22 | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | -3.54 | 11.22 | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | -3.54 | 11.15 | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | -3.54 | 11.14 | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | -3.55 | 11.11 | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | -3.55 | 11.11 | 7.12% |
| 12/5/2017 | 9.50% | 2.88% | -3.55 | 11.10 | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | -3.55 | 11.10 | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | -3.55 | 11.10 | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | -3.55 | 11.09 | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | -3.55 | 11.04 | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | -3.55 | 11.04 | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | -3.56 | 11.02 | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | -3.56 | 11.00 | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | -3.56 | 10.99 | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | -3.56 | 10.96 | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | -3.56 | 10.96 | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | -3.56 | 10.84 | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | -3.56 | 10.75 | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | -3.56 | 10.76 | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | -3.56 | 11.72 | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | -3.55 | 12.08 | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | -3.55 | 12.18 | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | -3.55 | 12.69 | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | -3.54 | 13.15 | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | -3.54 | 13.18 | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | -3.54 | 13.25 | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | -3.54 | 13.25 | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | -3.54 | 13.42 | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | -3.53 | 13.84 | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | -3.53 | 13.86 | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | -3.52 | 13.86 | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | -3.52 | 13.91 | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | -3.52 | 13.91 | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | -3.52 | 14.03 | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | -3.52 | 14.06 | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | -3.51 | 14.46 | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | -3.51 | 14.58 | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | -3.50 | 14.62 | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | -3.50 | 14.67 | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | -3.50 | 14.79 | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | -3.49 | 14.81 | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | -3.49 | 14.86 | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | -3.49 | 14.86 | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | -3.49 | 14.87 | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | -3.49 | 14.93 | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | -3.47 | 15.84 | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | -3.47 | 15.94 | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | -3.47 | 15.98 | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | -3.46 | 15.93 | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | -3.46 | 16.03 | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | -3.46 | 16.04 | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | -3.46 | 16.14 | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | -3.46 | 16.20 | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | -3.46 | 16.28 | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | -3.46 | 16.66 | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | -3.47 | 16.53 | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | -3.47 | 16.60 | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | -3.47 | 16.59 | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | -3.47 | 16.59 | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | -3.47 | 16.60 | 6.53% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 4/30/2019 | 9.73% | 3.11% | -3.47 | 16.53 | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | -3.47 | 16.53 | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | -3.47 | 16.54 | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | -3.47 | 16.55 | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | -3.47 | 16.63 | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | -3.48 | 16.75 | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | -3.48 | 16.78 | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | -3.48 | 16.88 | 6.81% |
| 8/12/2019 | 9.60% | 2.89% | -3.54 | 17.13 | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | -3.57 | 17.01 | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | -3.58 | 16.98 | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | -3.61 | 16.53 | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | -3.65 | 15.55 | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | -3.65 | 15.55 | 7.40% |
| 11/1/2019 | 9.35% | 2.59% | -3.65 | 15.52 | 6.76% |
| 11/29/2019 | 9.50% | 2.52% | -3.68 | 15.10 | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | -3.69 | 15.11 | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | -3.69 | 15.11 | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | -3.70 | 15.10 | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | -3.70 | 15.08 | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | -3.70 | 15.08 | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | -3.70 | 15.04 | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | -3.70 | 15.04 | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | -3.70 | 15.04 | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | -3.70 | 15.03 | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | -3.70 | 15.03 | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | -3.71 | 15.02 | 7.04% |
| 1/8/2020 | 10.02% | 2.43% | -3.72 | 14.99 | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | -3.73 | 14.95 | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | -3.73 | 14.94 | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | -3.73 | 14.93 | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | -3.75 | 15.13 | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | -3.76 | 15.16 | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | -3.76 | 15.16 | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | -3.77 | 15.16 | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | -3.78 | 15.16 | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | -3.78 | 15.36 | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | -3.81 | 16.54 | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | -3.83 | 19.18 | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | -3.88 | 21.82 | 7.63% |
| | | | | Average: | 5.80% |
| | | | | # of Rate Cases: | 870 |

Alternative Bond Yield Plus Risk Premium Backcast

| | [14] | [15] | [16] |
|---|---|---|---|
| | Actual | Projected | Difference |
| 2008 | 10.37% | 10.46% | -0.09% |
| 2009 | 10.52% | 10.58% | -0.06% |
| 2010 | 10.29% | 10.35% | -0.05% |
| 2011 | 10.19% | 10.22% | -0.03% |
| 2012 | 10.01% | 9.89% | 0.12% |
| 2013 | 9.81% | 9.76% | 0.05% |
| 2014 | 9.75% | 9.79% | -0.04% |
| 2015 | 9.60% | 9.72% | -0.12% |
| 2016 | 9.60% | 9.72% | -0.12% |
| 2017 | 9.68% | 9.61% | 0.07% |
| 2018 | 9.56% | 9.69% | -0.12% |
| 2019 | 9.64% | 9.73% | -0.09% |
| 2008-2019 Average | 9.92% | 9.96% | -0.04% |

[14] Average annual authorized ROE in [9]
[15] Equals the average annual projected ROE per the regression coefficients: [1] + ([1] x [11]) + ([2] x [12]) + [10]
[16] Equals [14] - [15]

I/A



Proof Concept: Earnings, Dividends, Book Value and
Stock Price Growth Rate Equivalence in Constant Growth DCF

| Line Description | IMPLIED GROWTH RATE AT ALLOWED ROE: | | |
|---|---|---|---|
| Input | Dividend Yield | 4.00% | [1] |
| Assumes g = Allowed ROE - Div. Yield | Assumed Growth Rate | 6.50% | |
| Input | Total Return | 10.50% | [1] |
| | | | |
| Input | Payout Ratio | 65.00% | [2] |
| Input | Book Value/Share | 20 | [2] |

| | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 250 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BV/S Escalates at Constant Growth g | Book Value/Share | $ 20.00 | $ 21.30 | $ 22.68 | $ 24.16 | $ 25.73 | $ 27.40 | $ 29.18 | $ 31.08 | $ 33.10 | $ 35.25 | $ 37.54 | $ 137,540,924.55 |
| Demonstrating Constant BV/S growth | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Earnings based on ROE applied to BV/S | Earnings/share | $ 2.10 | $ 2.24 | $ 2.38 | $ 2.54 | $ 2.70 | $ 2.88 | $ 3.06 | $ 3.26 | $ 3.48 | $ 3.70 | $ 3.94 | $ 14,441,797.08 |
| Demonstrating Constant EPS growth | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| | | | | | | | | | | | | | |
| Demonstrating Constant Return Earned based on BV/S and EPS | Allowed ROE | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% |
| Div/S based on EPS and Constant Payout ratio | Dividends/Share | $ 1.37 | $ 1.45 | $ 1.55 | $ 1.65 | $ 1.76 | $ 1.87 | $ 1.99 | $ 2.12 | $ 2.26 | $ 2.41 | $ 2.56 | $ 9,387,168.10 |
| Demonstrating Constant Div/S growth | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Retained Earnings based on difference between EPS and Div/S | Earnings retained to book value | $ 0.74 | $ 0.78 | $ 0.83 | $ 0.89 | $ 0.95 | $ 1.01 | $ 1.07 | $ 1.14 | $ 1.22 | $ 1.30 | $ 1.38 | $ 5,054,628.98 |
| Demonstrating Constant growth in Retained Earnings | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Demonstrating Constant Market/Book ratio | Market/Book Ratio | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 |
| DCF calculation of market price = [Div/S]*[1+g]/[ROE-g] | Market Price | $ 36.34 | $ 38.71 | $ 41.22 | $ 43.90 | $ 46.75 | $ 49.79 | $ 53.03 | $ 56.48 | $ 60.15 | $ 64.06 | $ 68.22 | $ 249,933,350.68 |
| | | | | | | | | | | | | | |
| Demonstrating Price Appreciation equals Long Term Growth Rate | Price Appreciation | 6.50% | OK | <== Price appreciation should equal long term growth rate | | | | | | | | | |
| Demonstrating Constant Price/Earnings Ratio | Price/Earnings | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 |
| | | | | | | | | | | | | | |
| Present Value Factor calculated based upon the current period and the Constant ROE | Present Value Factor | | 0.9050 | 0.8190 | 0.7412 | 0.6707 | 0.6070 | 0.5493 | 0.4971 | 0.4499 | 0.4071 | 0.3684 | 0.00 |

| **CASE 1** | **DIVIDENDS IN PERPETUITY** | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 250 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period | Present Value Dividend | | 1.3156 | 1.2680 | 1.2221 | 1.1778 | 1.1352 | 1.0941 | 1.0545 | 1.0163 | 0.9795 | 0.9441 | 0.00 |
| Total Value of investment sum of all Present Value Dividends in perpetuity (250 instances for demonstration purposes) | Value of Investment | | $ 36.34 | | | | | | | | | | |

| CASE 2 | 10-YEAR HOLDING PERIOD | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period | Present Value of Dividend | $ 1.32 | $ 1.27 | $ 1.22 | $ 1.18 | $ 1.14 | $ 1.09 | $ 1.05 | $ 1.02 | $ 0.98 | $ 0.94 |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value) | Present Value of Stock Price | -- | -- | -- | -- | -- | -- | -- | -- | -- | 25.14 |
| Value of dividends = sum of all Present Value Dividends for periods 1-10 | Value of Dividends | $ 11.21 | | | | | | | | | |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value) | Value of Stock Price | $ 25.14 | | | | | | | | | |
| Total Value of investment sum of all Present Value Dividends for periods 1-10 and Present Value of Stock in period 10 (Terminal Value) | Value of Investment | $ 36.34 | | | | | | | | | |

| CASE 3 | 5-YEAR HOLDING PERIOD | | | | | |
|---|---|---|---|---|---|---|
| Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period | Present Value of Dividend | $ 1.32 | $ 1.27 | $ 1.22 | $ 1.18 | $ 1.14 |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value) | Present Value of Stock Price | -- | -- | -- | -- | 30.22 |
| Value of dividends = sum of all Present Value Dividends for periods 1-5 | Value of Dividends | $ 6.12 | | | | |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value) | Value of Stock Price | $ 30.22 | | | | |
| Total Value of investment sum of all Present Value Dividends for periods 1-5 and Present Value of Stock in period 5 (Terminal Value) | Value of Investment | $ 36.34 | | | | |

[1] Note, for purposes of this exhibit, these data are illustrative only.
[2] Note: Illustrative only.

Growth Rate Regression Analysis

| Company | Ticker | Median P/E | Past 10 Year Earnings Growth Rate | Past 10 Year Dividend Growth Rate | Past 10 Year Book Value Growth Rate | Past 5 Year Earnings Growth Rate | Past 5 Year Dividend Growth Rate | Past 5 Year Book Value Growth Rate | Proj. Earnings Growth Rate | Proj. Dividend Growth Rate | Proj. Book Value Growth Rate | BxR Sustainable Growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Atmos Energy Corporation | ATO | 18.00 | 7.50% | 4.00% | 6.50% | 9.50% | 6.50% | 8.50% | 7.00% | 7.50% | 7.50% | 4.50% |
| Chesapeake Utilities Corporation | CPK | 17.00 | 9.00% | 5.00% | 10.00% | 8.00% | 6.00% | 10.50% | 9.00% | 9.00% | 10.00% | 5.51% |
| Spire Inc | SR | 18.00 | 3.50% | 4.00% | 7.00% | 9.50% | 5.50% | 7.00% | 5.50% | 5.00% | 8.50% | 2.80% |
| New Jersey Resources Corporation | NJR | 17.00 | 7.00% | 7.00% | 7.00% | 6.00% | 6.50% | 8.50% | 2.50% | 6.00% | 6.50% | 3.15% |
| NiSource Inc. | NI | 20.00 | -3.00% | -2.50% | -3.50% | -7.50% | -5.50% | -6.50% | 2.50% | 7.50% | 4.00% | 5.63% |
| Northwest Natural Gas Company | NWN | 21.00 | -10.50% | 2.50% | 2.00% | -18.00% | 1.00% | - | 22.50% | 0.50% | 1.50% | 5.06% |
| ONE Gas, Inc. | OGS | NMF | - | - | - | - | - | - | 7.00% | 8.00% | 4.00% | 3.90% |
| South Jersey Industries, Inc. | SJI | 18.00 | 1.50% | 8.00% | 6.50% | -2.50% | 6.00% | 6.00% | 9.50% | 3.50% | 5.00% | 5.06% |
| Southwest Gas Corporation | SWX | 17.00 | 7.00% | 8.50% | 5.50% | 4.50% | 10.50% | 6.00% | 8.00% | 5.00% | 7.00% | 5.04% |
| UGI Corporation | UGI | 17.00 | 6.00% | 7.50% | 8.00% | 9.50% | 7.00% | 6.00% | 9.50% | 6.00% | 8.00% | 9.10% |
| ALLETE, Inc. | ALE | 18.00 | 2.50% | 3.00% | 5.00% | 4.00% | 3.50% | 5.00% | 5.50% | 5.50% | 4.50% | 2.81% |
| Alliant Energy Corporation | LNT | 17.00 | 5.00% | 7.00% | 4.00% | 5.00% | 7.00% | 5.00% | 6.50% | 5.50% | 7.50% | 3.47% |
| Ameren Corporation | AEE | 17.00 | 1.00% | -2.00% | -0.50% | 6.50% | 3.00% | 2.50% | 6.00% | 5.00% | 6.00% | 4.60% |
| American Electric Power Company, Inc. | AEP | 15.00 | 3.00% | 4.50% | 4.00% | 4.00% | 5.50% | 3.00% | 5.00% | 5.50% | 4.50% | 3.15% |
| Avangrid, Inc. | AGR | NMF | - | - | - | - | - | - | 8.50% | 3.58% | 1.50% | 1.98% |
| Avista Corporation | AVA | 17.00 | 5.50% | 8.50% | 4.00% | 5.00% | 4.50% | 4.50% | 3.50% | 3.50% | 3.50% | 2.56% |
| Black Hills Corporation | BKH | 18.00 | 6.50% | 3.00% | 2.50% | 11.00% | 4.00% | 3.00% | 5.00% | 6.50% | 5.50% | 3.80% |
| CenterPoint Energy, Inc. | CNP | 18.00 | 1.00% | 4.50% | 7.00% | -1.00% | 5.00% | 3.50% | 6.50% | 2.00% | 6.50% | 3.36% |
| CMS Energy Corporation | CMS | 18.00 | 9.50% | 15.00% | 4.50% | 7.00% | 7.00% | 5.50% | 7.50% | 7.00% | 7.50% | 5.27% |
| Consolidated Edison, Inc. | ED | 15.00 | 2.50% | 2.00% | 4.00% | 2.00% | 2.50% | 4.00% | 3.00% | 3.50% | 3.50% | 2.81% |
| Dominion Energy Inc. | D | 20.00 | 3.00% | 7.50% | 4.50% | 3.50% | 7.50% | 6.50% | 7.00% | 4.50% | 6.50% | 3.24% |
| DTE Energy Company | DTE | 17.00 | 8.00% | 5.50% | 4.50% | 7.50% | 7.00% | 5.00% | 5.00% | 6.50% | 5.50% | 3.89% |
| Duke Energy Corporation | DUK | 18.00 | 2.50% | 7.00% | 1.00% | 0.50% | 3.00% | 1.50% | 6.00% | 2.50% | 2.50% | 2.72% |
| Edison International | EIX | 13.00 | -3.50% | 6.50% | 3.00% | -9.00% | 11.00% | 3.00% | NMF | 4.50% | 5.50% | 4.51% |
| El Paso Electric Company | EE | 16.00 | 4.00% | - | 7.00% | - | 8.00% | 5.50% | 3.00% | 6.50% | 3.50% | 2.40% |
| Entergy Corporation | ETR | 13.00 | -0.50% | 2.50% | 1.00% | 0.50% | 1.50% | -2.50% | 3.00% | 4.00% | 5.00% | 3.85% |
| Evergy, Inc. | EVRG | NMF | - | - | - | - | - | - | NMF | NMF | NMF | 2.72% |
| Exelon Corporation | EXC | 14.00 | -5.50% | -3.50% | 7.00% | -3.50% | -7.00% | 4.50% | 8.00% | 5.50% | 5.00% | 4.68% |
| FirstEnergy Corp. | FE | 17.00 | -7.00% | -2.50% | -8.00% | -2.50% | -5.00% | -17.50% | 7.00% | 3.00% | 8.50% | 6.00% |
| Hawaiian Electric Industries, Inc. | HE | 18.00 | 5.00% | - | 3.00% | 4.00% | - | 3.50% | 2.50% | 3.00% | 3.50% | 2.88% |
| IDACORP, Inc. | IDA | 14.00 | 7.00% | 6.50% | 5.50% | 4.00% | 10.00% | 5.00% | 3.50% | 7.00% | 4.00% | 3.52% |
| MGE Energy, Inc. | MGEE | 20.00 | 4.50% | 3.50% | 5.50% | 2.50% | 4.00% | 5.50% | 5.50% | 5.50% | 5.00% | 4.83% |
| NextEra Energy, Inc. | NEE | 16.00 | 6.00% | 9.00% | 8.50% | 6.00% | 10.50% | 9.50% | 10.00% | 10.50% | 7.00% | 4.68% |
| Eversource Energy | ES | 18.00 | 8.00% | 9.50% | 6.50% | 7.00% | 8.00% | 5.00% | 5.50% | 6.00% | 5.00% | 3.61% |
| NorthWestern Corporation | NWE | 16.00 | 8.50% | 5.00% | 5.50% | 7.00% | 7.00% | 8.00% | 2.00% | 4.50% | 3.50% | 2.79% |
| OGE Energy Corp. | OGE | 17.00 | 5.00% | 7.00% | 7.00% | 2.00% | 10.00% | 5.50% | 4.50% | 6.00% | 3.50% | 3.08% |
| Otter Tail Corporation | OTTR | 22.00 | 5.50% | 1.50% | - | 9.00% | 2.50% | 4.50% | 5.00% | 5.00% | 5.00% | 4.03% |
| Pinnacle West Capital Corporation | PNW | 15.00 | 4.50% | 2.50% | 2.50% | 5.00% | 3.00% | 4.50% | 4.00% | 6.00% | 3.50% | 3.20% |
| PNM Resources, Inc. | PNM | 18.00 | 7.00% | 2.50% | - | 6.00% | 11.00% | 1.00% | 7.00% | 7.00% | 5.00% | 3.78% |
| Portland General Electric Company | POR | 16.00 | 3.50% | 4.50% | 2.50% | 4.00% | 4.50% | 3.50% | 4.50% | 6.50% | 3.00% | 3.06% |
| PPL Corporation | PPL | 13.00 | - | 2.50% | 1.00% | -0.50% | 2.00% | -4.00% | 2.50% | 2.00% | 6.00% | 5.67% |
| Public Service Enterprise Group Incorporated | PEG | 13.00 | 1.50% | 3.50% | 6.50% | 1.00% | 4.00% | 5.00% | 6.00% | 5.00% | 5.00% | 4.84% |
| Sempra Energy | SRE | 19.00 | 1.00% | 10.00% | 5.50% | 2.00% | 7.50% | 4.00% | 11.00% | 8.00% | 7.00% | 4.83% |
| Southern Company | SO | 16.00 | 3.00% | 3.50% | 4.00% | 2.50% | 3.50% | 3.00% | 4.00% | 3.00% | 4.00% | 3.77% |
| WEC Energy Group, Inc. | WEC | 18.00 | 8.50% | 14.50% | 8.00% | 6.00% | 9.50% | 10.50% | 6.00% | 6.50% | 3.50% | 4.00% |
| Xcel Energy Inc. | XEL | 15.00 | 5.50% | 4.50% | 4.50% | 5.00% | 6.00% | 4.50% | 5.50% | 6.00% | 5.50% | 3.78% |

Notes:
Source: Value Line Reports as of April 17, 2020

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.38418 |
| R Square | 0.14760 |
| Adjusted R Square | 0.12629 |
| Standard Error | 1.90880 |
| Observations | 42 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 25.23570 | 25.23570 | 6.92620 | 0.01201 |
| Residual | 40 | 145.74049 | 3.64351 | | |
| Total | 41 | 170.97619 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 15.65068 | 0.59915 | 26.12165 | 0.00000 | 14.43976 | 16.86160 |
| Project Earnings Growth Rate | 22.84020 | 8.67865 | 2.63177 | 0.01201 | 5.29999 | 40.38041 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.00547 |
| R Square | 0.00003 |
| Adjusted R Square | -0.02436 |
| Standard Error | 2.13442 |
| Observations | 43 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 0.00558 | 0.00558 | 0.00122 | 0.97225 |
| Residual | 41 | 186.78512 | 4.55573 | | |
| Total | 42 | 186.79070 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.89876 | 0.95654 | 17.66646 | 0.00000 | 14.96698 | 18.83054 |
| Proj. Dividend Growth Rate | 0.59232 | 16.92641 | 0.03499 | 0.97225 | -33.59125 | 34.77589 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.024240794 |
| R Square | 0.000587616 |
| Adjusted R Square | -0.023788296 |
| Standard Error | 2.133821354 |
| Observations | 43 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 0.10976122 | 0.10976122 | 0.024106425 | 0.877376303 |
| Residual | 41 | 186.6809365 | 4.553193572 | | |
| Total | 42 | 186.7906977 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.7812709 | 1.013100223 | 16.5642752 | 9.07295E-20 | 14.73527349 | 18.82726831 |
| Proj. Book Value Growth Rate | 2.809364548 | 18.09429609 | 0.155262439 | 0.877376303 | -33.73280775 | 39.35153684 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.02706 |
| R Square | 0.00073 |
| Adjusted R Square | -0.02425 |
| Standard Error | 2.06671 |
| Observations | 42 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.12522 | 0.12522 | 0.02932 | 0.86491 |
| Residual | 40 | 170.85097 | 4.27127 | | |
| Total | 41 | 170.97619 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.97897 | 0.41265 | 41.14633 | 0.00000 | 16.14498 | 17.81296 |
| Past 10 Year Earnings Growth Rate | 1.25972 | 7.35720 | 0.17122 | 0.86491 | -13.60973 | 16.12917 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.10269 |
| R Square | 0.01055 |
| Adjusted R Square | -0.01483 |
| Standard Error | 2.16518 |
| Observations | 41 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1.94861 | 1.94861 | 0.41566 | 0.52288 |
| Residual | 39 | 182.83187 | 4.68800 | | |
| Total | 40 | 184.78049 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.65041 | 0.54605 | 30.49253 | 0.00000 | 15.54592 | 17.75489 |
| Past 10 Year Dividend Growth Rate | 5.59672 | 8.68089 | 0.64472 | 0.52288 | -11.96204 | 23.15549 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.02129 |
| R Square | 0.00045 |
| Adjusted R Square | -0.02518 |
| Standard Error | 2.01884 |
| Observations | 41 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.07205 | 0.07205 | 0.01768 | 0.89491 |
| Residual | 39 | 158.95234 | 4.07570 | | |
| Total | 40 | 159.02439 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.83684 | 0.52824 | 31.87335 | 0.00000 | 15.76837 | 17.90531 |
| Past 10 Year Book Value Growth Rate | -1.28712 | 9.68080 | -0.13296 | 0.89491 | -20.86839 | 18.29415 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.03917 |
| R Square | 0.00153 |
| Adjusted R Square | -0.02343 |
| Standard Error | 2.15418 |
| Observations | 42 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.28526 | 0.28526 | 0.06147 | 0.80545 |
| Residual | 40 | 185.61951 | 4.64049 | | |
| Total | 41 | 185.90476 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.90466 | 0.38411 | 44.01028 | 0.00000 | 16.12835 | 17.68097 |
| Past 5 Year Earnings Growth Rate | 1.51848 | 6.12452 | 0.24793 | 0.80545 | -10.85964 | 13.89659 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.03246 |
| R Square | 0.00105 |
| Adjusted R Square | -0.02392 |
| Standard Error | 2.15304 |
| Observations | 42 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.19554 | 0.19554 | 0.04218 | 0.83832 |
| Residual | 40 | 185.42351 | 4.63559 | | |
| Total | 41 | 185.61905 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.99106 | 0.53567 | 31.71933 | 0.00000 | 15.90844 | 18.07369 |
| Past 5 Year Dividend Growth Rate | -1.68983 | 8.22774 | -0.20538 | 0.83832 | -18.31872 | 14.93906 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.098261747 |
| R Square | 0.009655371 |
| Adjusted R Square | -0.015103245 |
| Standard Error | 2.050570223 |
| Observations | 42 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1.639803818 | 1.639803818 | 0.389980238 | 0.535855746 |
| Residual | 40 | 168.1935295 | 4.204838238 | | |
| Total | 41 | 169.8333333 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.6655746 | 0.415066707 | 40.15155718 | 6.07414E-34 | 15.8266935 | 17.50445571 |
| Past 5 Year Book Value Growth Rate | 4.231751789 | 6.776397699 | 0.624483978 | 0.535855746 | -9.463858835 | 17.92736241 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.116023492 |
| R Square | 0.013461451 |
| Adjusted R Square | -0.010600465 |
| Standard Error | 2.083827353 |
| Observations | 43 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 2.42932228 | 2.42932228 | 0.559450497 | 0.458750721 |
| Residual | 41 | 178.035794 | 4.342336439 | | |
| Total | 42 | 180.4651163 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 17.54125733 | 1.322059625 | 13.26812875 | 1.99027E-16 | 14.87130375 | 20.2112109 |
| BxR Sustainable Growth | -24.16089973 | 32.30221258 | -0.747964235 | 0.458750721 | -89.39654147 | 41.07474201 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.748562859 |
| R Square | 0.560346353 |
| Adjusted R Square | 0.384484895 |
| Standard Error | 1.332008527 |
| Observations | 36 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 10 | 56.53272099 | 5.653272099 | 3.186294244 | 0.009062744 |
| Residual | 25 | 44.3561679 | 1.774246716 | | |
| Total | 35 | 100.8888889 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.98268641 | 1.065469549 | 15.93915699 | 1.31988E-14 | 14.7883108 | 19.17706202 |
| Past 10 YearEarningsGrowth Rate | 8.159157225 | 17.84182259 | 0.457305143 | 0.651401031 | -28.58676425 | 44.9050787 |
| Past 10 YearDividendGrowth Rate | 6.854393677 | 8.036053791 | 0.852955176 | 0.401782509 | -9.696168918 | 23.40495627 |
| Past 10 YearBook ValueGrowth Rate | -20.07636098 | 23.02960726 | -0.871763064 | 0.391633055 | -67.50672499 | 27.35400302 |
| Past 5 YearEarningsGrowth Rate | 16.82718561 | 11.91068235 | 1.41278099 | 0.170049431 | -7.703323881 | 41.35769509 |
| Past 5 YearDividendGrowth Rate | -1.506977664 | 10.56977991 | -0.142574176 | 0.887769352 | -23.27584688 | 20.26189156 |
| Past 5 YearBook ValueGrowth Rate | -0.226215047 | 19.05041108 | -0.011874549 | 0.990619958 | -39.46127111 | 39.00884102 |
| Proj.EarningsGrowth Rate | 69.52486402 | 16.69329139 | 4.16483858 | 0.00032412 | 35.14438683 | 103.9053412 |
| Proj.DividendGrowth Rate | -20.66089038 | 17.0184553 | -1.214028536 | 0.236081248 | -55.71105517 | 14.38927441 |
| Proj. Book Value Growth Rate | -12.58594719 | 15.49360334 | -0.812331832 | 0.424269388 | -44.49562059 | 19.32372621 |
| BxR Sustainable Growth | -84.21749433 | 31.63689195 | -2.66200278 | 0.013382066 | -149.374893 | -19.06009567 |

Bond Yield Plus Risk Premium - Settled Cases

| | [1] Constant | [2] Slope | [3] 30-Year Treasury Yield | [4] Risk Premium | [5] Return on Equity |
|---|---|---|---|---|---|
| Current | -1.63% | -2.40% | 1.37% | 8.67% | 10.04% |
| Near-Term Projected | -1.63% | -2.40% | 1.75% | 8.08% | 9.83% |
| Long-Term Projected | -1.63% | -2.40% | 3.45% | 6.45% | 9.90% |

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Rebuttal Exhibit DWD-5
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]

Bond Yield Plus Risk Premium - Fully Litigated Cases

| | [1] Constant | [2] Slope | [3] 30-Year Treasury Yield | [4] Risk Premium | [5] Return on Equity |
|---|---|---|---|---|---|
| Current | -2.64% | -2.74% | 1.37% | 9.12% | 10.49% |
| Near Term Projected | -2.64% | -2.74% | 1.75% | 8.45% | 10.20% |
| Long-Term Projected | -2.64% | -2.74% | 3.45% | 6.59% | 10.04% |

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Rebuttal Exhibit DWD-5
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]

| | Litigated | Settled | Difference |
|---|---|---|---|
| Authorized ROEs January 2015 - April 17, 2020 | 9.54% | 9.66% | 0.13% |

Source: Regulatory Research Associates

Implied Return on Equity with M/B Ratio at Unity

| Institution Name | Ticker | ROACE (%) 2019Y | Price/ Book (%) 2019Y |
|---|---|---|---|
| ALLETE, Inc. | ALE | 8.43 | 187.9 |
| Alliant Energy Corporation | LNT | 11.58 | 257.6 |
| Ameren Corporation | AEE | 10.55 | 234.6 |
| American Electric Power Company, Inc. | AEP | 9.92 | 237.9 |
| Atmos Energy Corporation | ATO | 9.39 | 236.4 |
| Avangrid, Inc. | AGR | 4.62 | 103.8 |
| Avista Corporation | AVA | 10.50 | 166.6 |
| Black Hills Corporation | BKH | 8.67 | 204.4 |
| CenterPoint Energy, Inc. | CNP | 10.34 | 206.9 |
| Chesapeake Utilities Corporation | CPK | 11.99 | 278.3 |
| CMS Energy Corporation | CMS | 13.91 | 355.5 |
| Consolidated Edison, Inc. | ED | 7.63 | 167.2 |
| Dominion Energy, Inc. | D | 5.15 | 234.4 |
| DTE Energy Company | DTE | 10.97 | 213.9 |
| Duke Energy Corporation | DUK | 8.37 | 149.1 |
| Edison International | EIX | 11.10 | 205.2 |
| El Paso Electric Company | EE | 10.33 | 227.3 |
| Entergy Corporation | ETR | 12.95 | 233.4 |
| Evergy, Inc. | EVRG | 7.40 | 172.1 |
| Eversource Energy | ES | 7.61 | 222.2 |
| Exelon Corporation | EXC | 9.29 | 137.7 |
| FirstEnergy Corp. | FE | 12.84 | 376.7 |
| Hawaiian Electric Industries, Inc. | HE | 9.84 | 223.9 |
| IDACORP, Inc. | IDA | 9.64 | 218.4 |
| MGE Energy, Inc. | MGEE | 10.38 | 319.3 |
| New Jersey Resources Corporation | NJR | 11.07 | 262.3 |
| NextEra Energy, Inc. | NEE | 10.67 | 320.0 |
| NiSource Inc. | NI | 6.58 | 208.3 |
| Northwest Natural Holding Company | NWN | 7.42 | 259.4 |
| NorthWestern Corporation | NWE | 10.11 | 177.3 |
| OGE Energy Corp. | OGE | 10.68 | 215.0 |
| ONE Gas, Inc. | OGS | 8.89 | 231.9 |
| Otter Tail Corporation | OTTR | 11.59 | 263.6 |
| Pinnacle West Capital Corporation | PNW | 10.08 | 186.2 |
| PNM Resources, Inc. | PNM | 4.65 | 240.6 |
| Portland General Electric Company | POR | 8.39 | 192.5 |
| PPL Corporation | PPL | 14.43 | 211.9 |
| Public Service Enterprise Group Incorporated | PEG | 11.43 | 197.2 |
| Sempra Energy | SRE | 13.07 | 250.1 |
| South Jersey Industries, Inc. | SJI | 5.35 | 214.0 |
| Southern Company | SO | 17.72 | 243.9 |
| Southwest Gas Holdings, Inc. | SWX | 8.94 | 166.8 |
| Spire Inc. | SR | 7.66 | 193.3 |
| UGI Corporation | UGI | 6.79 | 275.2 |
| WEC Energy Group, Inc. | WEC | 11.34 | 287.7 |
| Xcel Energy Inc. | XEL | 10.85 | 251.6 |

Source: S&P Global Market Intelligence

Implied Return on Equity with M/B Ratio at Unity

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.419390367 |
| R Square | 0.17588828 |
| Adjusted R Square | 0.157158468 |
| Standard Error | 48.54620381 |
| Observations | 46 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 22131.66238 | 22131.66238 | 9.39081936 | 0.003716974 |
| Residual | 44 | 103696.2918 | 2356.733905 | | |
| Total | 45 | 125827.9542 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 143.0499577 | 28.15860109 | 5.080151435 | 7.39609E-06 | 86.30002615 | 199.7998893 |
| ROACE | 8.510111287 | 2.777048702 | 3.06444438 | 0.003716974 | 2.913337381 | 14.10688519 |

| ROE (%) | PRICE/BOOK |
|---|---|
| -5.06 | 100.00 |
| -3.88 | 110.00 |

Constant Growth Discounted Cash Flow Model and Credit Ratings
30 Day Dividend Yield

| Company | Ticker | [1] Dividend Yield | [2] Expected Dividend Yield | [3] Yahoo Earnings Growth | [4] Zacks Earnings Growth | [5] Average Earnings Growth | [6] Mean ROE | [7] S&P Issuer Credit Rating | [8] Numeric Credit Score |
|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 3.00% | 3.11% | 7.00% | 7.20% | 7.10% | 10.21% | BBB+ | 5 |
| Alliant Energy Corporation | LNT | 2.68% | 2.75% | 5.40% | 5.49% | 5.45% | 8.20% | A- | 4 |
| Ameren Corporation | AEE | 2.50% | 2.57% | 6.05% | 5.65% | 5.85% | 8.42% | BBB+ | 5 |
| American Electric Power Company, Inc. | AEP | 2.85% | 2.92% | 4.60% | 6.24% | 5.42% | 8.34% | A- | 4 |
| Avangrid, Inc. | AGR | 3.40% | 3.46% | 3.50% | 3.36% | 3.43% | 6.89% | BBB+ | 5 |
| Avista Corporation | AVA | 3.30% | 3.42% | 6.20% | 7.39% | 6.80% | 10.21% | BBB | 6 |
| CMS Energy Corporation | CMS | 2.50% | 2.58% | 7.50% | 6.42% | 6.96% | 9.54% | BBB+ | 5 |
| Consolidated Edison, Inc. | ED | 3.37% | 3.40% | 2.37% | 2.00% | 2.19% | 5.59% | A- [7] | 4 |
| Dominion Energy, Inc. | D | 4.50% | 4.60% | 4.41% | 4.78% | 4.60% | 9.20% | BBB+ | 5 |
| Duke Energy Corporation | DUK | 4.03% | 4.12% | 4.40% | 4.84% | 4.62% | 8.74% | A- | 4 |
| Edison International | EIX | 3.34% | 3.42% | 3.90% | 5.42% | 4.66% | 8.08% | BBB | 6 |
| Entergy Corporation | ETR | 2.96% | 3.01% | -1.50% | 7.00% | 2.75% | 5.76% | BBB+ | 5 |
| Evergy, Inc. | EVRG | 2.98% | 3.08% | 6.70% | 6.57% | 6.64% | 9.71% | A- | 4 |
| Eversource Energy | ES | 2.58% | 2.65% | 5.45% | 5.63% | 5.54% | 8.19% | A- | 4 |
| Exelon Corporation | EXC | 3.26% | 3.30% | 0.46% | 4.19% | 2.33% | 5.62% | BBB+ | 5 |
| FirstEnergy Corp. | FE | 3.16% | 3.15% | -6.60% | 6.00% | -0.30% | 2.85% | BBB | 6 |
| Hawaiian Electric Industries, Inc. | HE | 2.70% | 2.75% | 3.40% | 4.22% | 3.81% | 6.56% | BBB- | 7 |
| IDACORP, Inc. | IDA | 2.46% | 2.50% | 2.50% | 3.85% | 3.18% | 5.68% | BBB | 6 |
| MGE Energy, Inc. | MGEE | 1.79% | 1.82% | 4.00% | N/A | 4.00% | 5.82% | AA- | 1 |
| NextEra Energy, Inc. | NEE | 1.96% | 2.04% | 7.99% | 7.98% | 7.99% | 10.03% | A- | 4 |
| NorthWestern Corporation | NWE | 3.11% | 3.15% | 3.23% | 2.75% | 2.99% | 6.14% | BBB | 6 |
| OGE Energy Corp. | OGE | 3.43% | 3.50% | 3.50% | 4.26% | 3.88% | 7.38% | BBB+ | 5 |
| Otter Tail Corporation | OTTR | 2.80% | 2.91% | 9.00% | 7.00% | 8.00% | 10.91% | BBB | 6 |
| Pinnacle West Capital Corporation | PNW | 3.34% | 3.42% | 4.11% | 4.91% | 4.51% | 7.93% | A- | 4 |
| PNM Resources, Inc. | PNM | 2.37% | 2.44% | 6.25% | 5.40% | 5.83% | 8.26% | BBB+ | 5 |
| Portland General Electric Company | POR | 2.64% | 2.70% | 4.80% | 4.78% | 4.79% | 7.49% | BBB+ | 5 |
| PPL Corporation | PPL | 4.59% | 4.60% | 0.50% | N/A | 0.50% | 5.10% | A- | 4 |
| Sempra Energy | SRE | 2.49% | 2.60% | 10.05% | 7.73% | 8.89% | 11.49% | BBB+ | 5 |
| Southern Company | SO | 3.72% | 3.78% | 1.53% | 4.50% | 3.02% | 6.79% | A- | 4 |
| WEC Energy Group, Inc. | WEC | 2.64% | 2.72% | 6.05% | 6.14% | 6.10% | 8.81% | A- | 4 |
| Xcel Energy Inc. | XEL | 2.47% | 2.54% | 6.10% | 5.42% | 5.76% | 8.30% | A- | 4 |
| PROXY GROUP MEAN | | 3.00% | 3.07% | 4.29% | 5.42% | 4.75% | 7.81% | BBB+ | 4.74 |
| PROXY GROUP MEDIAN | | 2.96% | 3.01% | 4.41% | 5.42% | 4.66% | 8.19% | BBB+ | 5.00 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.007937496 |
| R Square | 6.30038E-05 |
| Adjusted R Square | -0.034417582 |
| Standard Error | 0.01968308 |
| Observations | 31 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 7.07911E-07 | 7.0791E-07 | 0.0018272 | 0.96619692 |
| Residual | 29 | 0.011235286 | 0.00038742 | | |
| Total | 30 | 0.011235994 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.077483509 | 0.015966233 | 4.85296127 | 3.817E-05 | 0.0448289 | 0.1101381 |
| Credit Score | 0.000140355 | 0.003283457 | 0.04274607 | 0.9661969 | -0.00657507 | 0.0068558 |

Notes:
[1] Source: Exhibit JRW-7
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: Exhibit JRW-7
[4] Source: Exhibit JRW-7
[5] Equals Average([3], [4])
[6] Equals [2] + [5]
[7] Source: Exhibit JRW-2. Note: Exh. JRW-2 incorrectly denotes ED as being rated BBB+
[8] AA- = 1; A+ = 2; A = 3; A- = 4; BBB+ = 5; BBB = 6; BBB- = 7

Constant Growth Discounted Cash Flow Model and Credit Ratings
90 Day Dividend Yield

| Company | Ticker | [1] Dividend Yield | [2] Expected | [3] Yahoo | [4] Zacks | [5] Average | [6] Mean | [7] S&P | [8] Numeric |
|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 3.00% | 3.10% | 7.00% | 7.20% | 7.10% | 10.20% | BBB+ | 5 |
| Alliant Energy Corporation | LNT | 2.80% | 2.88% | 5.40% | 5.49% | 5.45% | 8.32% | A- | 4 |
| Ameren Corporation | AEE | 2.58% | 2.65% | 6.05% | 5.65% | 5.85% | 8.50% | BBB+ | 5 |
| American Electric Power Company, Inc. | AEP | 2.97% | 3.05% | 4.60% | 6.24% | 5.42% | 8.47% | A- | 4 |
| Avangrid, Inc. | AGR | 3.50% | 3.56% | 3.50% | 3.36% | 3.43% | 6.99% | BBB+ | 5 |
| Avista Corporation | AVA | 3.37% | 3.48% | 6.20% | 7.39% | 6.80% | 10.28% | BBB | 6 |
| CMS Energy Corporation | CMS | 2.58% | 2.67% | 7.50% | 6.42% | 6.96% | 9.63% | BBB+ | 5 |
| Consolidated Edison, Inc. | ED | 3.41% | 3.45% | 2.37% | 2.00% | 2.19% | 5.63% | A- [7] | 4 |
| Dominion Energy, Inc. | D | 4.56% | 4.67% | 4.41% | 4.78% | 4.60% | 9.26% | BBB+ | 5 |
| Duke Energy Corporation | DUK | 4.10% | 4.20% | 4.40% | 4.84% | 4.62% | 8.82% | A- | 4 |
| Edison International | EIX | 3.52% | 3.61% | 3.90% | 5.42% | 4.66% | 8.27% | BBB | 6 |
| Entergy Corporation | ETR | 3.09% | 3.13% | -1.50% | 7.00% | 2.75% | 5.88% | BBB+ | 5 |
| Evergy, Inc. | EVRG | 3.11% | 3.21% | 6.70% | 6.57% | 6.64% | 9.84% | A- | 4 |
| Eversource Energy | ES | 2.68% | 2.76% | 5.45% | 5.63% | 5.54% | 8.30% | A- | 4 |
| Exelon Corporation | EXC | 3.34% | 3.38% | 0.46% | 4.19% | 2.33% | 5.71% | BBB+ | 5 |
| FirstEnergy Corp. | FE | 3.23% | 3.22% | -6.60% | 6.00% | -0.30% | 2.92% | BBB | 6 |
| Hawaiian Electric Industries, Inc. | HE | 2.81% | 2.86% | 3.40% | 4.22% | 3.81% | 6.67% | BBB- | 7 |
| IDACORP, Inc. | IDA | 2.50% | 2.54% | 2.50% | 3.85% | 3.18% | 5.71% | BBB | 6 |
| MGE Energy, Inc. | MGEE | 1.82% | 1.85% | 4.00% | N/A | 4.00% | 5.85% | AA- | 1 |
| NextEra Energy, Inc. | NEE | 2.08% | 2.16% | 7.99% | 7.98% | 7.99% | 10.15% | A- | 4 |
| NorthWestern Corporation | NWE | 3.17% | 3.21% | 3.23% | 2.75% | 2.99% | 6.20% | BBB | 6 |
| OGE Energy Corp. | OGE | 3.54% | 3.61% | 3.50% | 4.26% | 3.88% | 7.49% | BBB+ | 5 |
| Otter Tail Corporation | OTTR | 2.84% | 2.95% | 9.00% | 7.00% | 8.00% | 10.95% | BBB | 6 |
| Pinnacle West Capital Corporation | PNW | 3.44% | 3.51% | 4.11% | 4.91% | 4.51% | 8.02% | A- | 4 |
| PNM Resources, Inc. | PNM | 2.43% | 2.50% | 6.25% | 5.40% | 5.83% | 8.32% | BBB+ | 5 |
| Portland General Electric Company | POR | 2.72% | 2.78% | 4.80% | 4.78% | 4.79% | 7.57% | BBB+ | 5 |
| PPL Corporation | PPL | 4.79% | 4.80% | 0.50% | N/A | 0.50% | 5.30% | A- | 4 |
| Sempra Energy | SRE | 2.59% | 2.70% | 10.05% | 7.73% | 8.89% | 11.59% | BBB+ | 5 |
| Southern Company | SO | 3.90% | 3.96% | 1.53% | 4.50% | 3.02% | 6.98% | A- | 4 |
| WEC Energy Group, Inc. | WEC | 2.73% | 2.82% | 6.05% | 6.14% | 6.10% | 8.91% | A- | 4 |
| Xcel Energy Inc. | XEL | 2.55% | 2.63% | 6.10% | 5.42% | 5.76% | 8.39% | A- | 4 |
| PROXY GROUP MEAN | | 3.09% | 3.16% | 4.29% | 5.42% | 4.75% | 7.91% | BBB+ | 4.74 |
| PROXY GROUP MEDIAN | | 3.00% | 3.10% | 4.41% | 5.42% | 4.66% | 8.30% | BBB+ | 5.00 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.006262744 |
| R Square | 3.9222E-05 |
| Adjusted R Square | -0.034442184 |
| Standard Error | 0.019641716 |
| Observations | 31 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 4.38837E-07 | 4.3884E-07 | 0.0011375 | 0.97332626 |
| Residual | 29 | 0.011188114 | 0.0003858 | | |
| Total | 30 | 0.011188552 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.078554934 | 0.01593268 | 4.9304282 | 3.078E-05 | 0.04596894 | 0.1111409 |
| Credit Score | 0.000110507 | 0.003276557 | 0.03372657 | 0.9733263 | -0.0065908 | 0.0068118 |

Notes:
[1] Source: Exhibit JRW-7
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: Exhibit JRW-7
[4] Source: Exhibit JRW-7
[5] Equals Average([3], [4])
[6] Equals [2] + [5]
[7] Source: Exhibit JRW-2. Note: Exh. JRW-2 incorrectly denotes ED as being rated BBB+
[8] AA- = 1; A+ = 2; A = 3; A- = 4; BBB+ = 5; BBB = 6; BBB- = 7

Constant Growth Discounted Cash Flow Model and Credit Ratings
180 Day Dividend Yield

| Company | Ticker | [1] Dividend Yield | [2] Expected | [3] Yahoo | [4] Zacks | [5] Average | [6] Mean | [7] S&P | [8] Numeric |
|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 2.94% | 3.04% | 7.00% | 7.20% | 7.10% | 10.14% | BBB+ | 5 |
| Alliant Energy Corporation | LNT | 2.89% | 2.97% | 5.40% | 5.49% | 5.45% | 8.41% | A- | 4 |
| Ameren Corporation | AEE | 2.58% | 2.65% | 6.05% | 5.65% | 5.85% | 8.50% | BBB+ | 5 |
| American Electric Power Company, Inc. | AEP | 3.03% | 3.11% | 4.60% | 6.24% | 5.42% | 8.53% | A- | 4 |
| Avangrid, Inc. | AGR | 3.49% | 3.55% | 3.50% | 3.36% | 3.43% | 6.98% | BBB+ | 5 |
| Avista Corporation | AVA | 3.45% | 3.56% | 6.20% | 7.39% | 6.80% | 10.36% | BBB | 6 |
| CMS Energy Corporation | CMS | 2.64% | 2.73% | 7.50% | 6.42% | 6.96% | 9.69% | BBB+ | 5 |
| Consolidated Edison, Inc. | ED | 3.43% | 3.46% | 2.37% | 2.00% | 2.19% | 5.65% | A- [7] | 4 |
| Dominion Energy, Inc. | D | 4.71% | 4.82% | 4.41% | 4.78% | 4.60% | 9.41% | BBB+ | 5 |
| Duke Energy Corporation | DUK | 4.14% | 4.23% | 4.40% | 4.84% | 4.62% | 8.86% | A- | 4 |
| Edison International | EIX | 3.58% | 3.67% | 3.90% | 5.42% | 4.66% | 8.33% | BBB | 6 |
| Entergy Corporation | ETR | 3.26% | 3.30% | -1.50% | 7.00% | 2.75% | 6.05% | BBB+ | 5 |
| Evergy, Inc. | EVRG | 3.16% | 3.27% | 6.70% | 6.57% | 6.64% | 9.90% | A- | 4 |
| Eversource Energy | ES | 2.77% | 2.85% | 5.45% | 5.63% | 5.54% | 8.39% | A- | 4 |
| Exelon Corporation | EXC | 3.27% | 3.31% | 0.46% | 4.19% | 2.33% | 5.64% | BBB+ | 5 |
| FirstEnergy Corp. | FE | 3.35% | 3.34% | -6.60% | 6.00% | -0.30% | 3.04% | BBB | 6 |
| Hawaiian Electric Industries, Inc. | HE | 2.85% | 2.90% | 3.40% | 4.22% | 3.81% | 6.71% | BBB- | 7 |
| IDACORP, Inc. | IDA | 2.51% | 2.55% | 2.50% | 3.85% | 3.18% | 5.73% | BBB | 6 |
| MGE Energy, Inc. | MGEE | 1.86% | 1.90% | 4.00% | N/A | 4.00% | 5.90% | AA- | 1 |
| NextEra Energy, Inc. | NEE | 2.20% | 2.29% | 7.99% | 7.98% | 7.99% | 10.27% | A- | 4 |
| NorthWestern Corporation | NWE | 3.17% | 3.22% | 3.23% | 2.75% | 2.99% | 6.21% | BBB | 6 |
| OGE Energy Corp. | OGE | 3.56% | 3.63% | 3.50% | 4.26% | 3.88% | 7.51% | BBB+ | 5 |
| Otter Tail Corporation | OTTR | 2.84% | 2.95% | 9.00% | 7.00% | 8.00% | 10.95% | BBB | 6 |
| Pinnacle West Capital Corporation | PNW | 3.37% | 3.44% | 4.11% | 4.91% | 4.51% | 7.95% | A- | 4 |
| PNM Resources, Inc. | PNM | 2.43% | 2.50% | 6.25% | 5.40% | 5.83% | 8.33% | BBB+ | 5 |
| Portland General Electric Company | POR | 2.75% | 2.81% | 4.80% | 4.78% | 4.79% | 7.60% | BBB+ | 5 |
| PPL Corporation | PPL | 5.09% | 5.10% | 0.50% | N/A | 0.50% | 5.60% | A- | 4 |
| Sempra Energy | SRE | 2.68% | 2.80% | 10.05% | 7.73% | 8.89% | 11.69% | BBB+ | 5 |
| Southern Company | SO | 4.10% | 4.16% | 1.53% | 4.50% | 3.02% | 7.17% | A- | 4 |
| WEC Energy Group, Inc. | WEC | 2.79% | 2.87% | 6.05% | 6.14% | 6.10% | 8.97% | A- | 4 |
| Xcel Energy Inc. | XEL | 2.59% | 2.66% | 6.10% | 5.42% | 5.76% | 8.42% | A- | 4 |
| PROXY GROUP MEAN | | 3.14% | 3.21% | 4.29% | 5.42% | 4.75% | 7.96% | BBB+ | 4.74 |
| PROXY GROUP MEDIAN | | 3.03% | 3.11% | 4.41% | 5.42% | 4.66% | 8.33% | BBB+ | 5.00 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.00066414 |
| R Square | 4.41E-07 |
| Adjusted R Square | -0.034482302 |
| Standard Error | 0.019542735 |
| Observations | 31 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 4.88527E-09 | 4.8853E-09 | 1.279E-05 | 0.99717086 |
| Residual | 29 | 0.011075636 | 0.00038192 | | |
| Total | 30 | 0.011075641 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.079588298 | 0.015852389 | 5.02058685 | 2.396E-05 | 0.04716652 | 0.1120101 |
| Credit Score | 1.16596E-05 | 0.003260045 | 0.00357651 | 0.9971709 | -0.00665588 | 0.0066792 |

Notes:
[1] Source: Exhibit JRW-7
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: Exhibit JRW-7
[4] Source: Exhibit JRW-7
[5] Equals Average([3], [4])
[6] Equals [2] + [5]
[7] Source: Exhibit JRW-2. Note: Exh. JRW-2 incorrectly denotes ED as being rated BBB+
[8] AA- = 1; A+ = 2; A = 3; A- = 4; BBB+ = 5; BBB = 6; BBB- = 7

Credit Ratings - Dr. Woolridge's Proxy Group

| Company | Ticker | Moody's Long-Term Issuer | Moody's Corporate Long-Term | S&P Long-Term Issuer | S&P Corporate Long-Term |
|---|---|---|---|---|---|
| **ALLETE, Inc.** | **ALE** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| Superior Water, Light and Power Company | | A3 | | | |
| **Alliant Energy Corporation** | **LNT** | **Baa2** | **Baa2** | **A-** | **A-** |
| Interstate Power and Light Company | | Baa1 | Baa1 | A- | A- |
| Wisconsin Power and Light Company | | A3 | A3 | A | A |
| **Ameren Corporation** | **AEE** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| Ameren Illinois Company | | A3 | A3 | BBB+ | BBB+ |
| Union Electric Company | | Baa1 | Baa1 | BBB+ | BBB+ |
| **American Electric Power Company, Inc.** | **AEP** | | **Baa1** | **A-** | **A-** |
| AEP Texas Inc. | | Baa1 | Baa1 | A- | A- |
| Appalachian Power Company | | Baa1 | Baa1 | A- | A- |
| Indiana Michigan Power Company | | A3 | A3 | A- | A- |
| Kentucky Power Company | | Baa3 | Baa3 | A- | A- |
| Ohio Power Company | | A2 | A2 | A- | A- |
| Public Service Company of Oklahoma | | A3 | A3 | A- | A- |
| Southwestern Electric Power Company | | Baa2 | Baa2 | A- | A- |
| **Avangrid, Inc.** | **AGR** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| New York State Electric & Gas Corporation | | A3 | A3 | A- | A- |
| United Illuminating Company | | Baa1 | Baa1 | A- | A- |
| Rochester Gas and Electric Corporation | | A3 | A3 | A- | A- |
| Central Maine Power Company | | A2 | A2 | A | A |
| **Avista Corporation** | **AVA** | **Baa2** | | **BBB** | |
| Alaska Electric Light and Power | | Baa3 | Baa3 | | |
| **CMS Energy Corporation** | **CMS** | | **Baa1** | **BBB+** | **BBB+** |
| Consumers Energy Company | | | (P)A2 | A- | A- |
| **Consolidated Edison, Inc.** | **ED** | **Baa2** | **Baa2** | **A-** | **A-** |
| Consolidated Edison Company of New York, Inc. | | Baa1 | Baa1 | A- | A- |
| Orange and Rockland Utilities, Inc. | | Baa1 | Baa1 | A- | A- |
| Rockland Electric | | | | A- | A- |
| **Dominion Energy, Inc.** | **D** | | **Baa2** | **BBB+** | **BBB+** |
| Dominion Energy South Carolina, Inc. | | Baa2 | Baa2 | BBB+ | BBB+ |
| Virginia Electric and Power Company | | A2 | A2 | BBB+ | BBB+ |
| **Duke Energy Corporation** | **DUK** | **Baa1** | **Baa1** | **A-** | **A-** |
| Duke Energy Carolinas, LLC | | A1 | A1 | A- | A- |
| Duke Energy Florida, LLC | | A3 | A3 | A- | A- |
| Duke Energy Indiana, LLC | | A2 | A2 | A- | A- |
| Duke Energy Kentucky, Inc. | | | Baa1 | A- | A- |
| Duke Energy Ohio, Inc. | | Baa1 | Baa1 | A- | A- |
| Duke Energy Progress, LLC | | A2 | A2 | A- | A- |
| **Edison International** | **EIX** | **Baa3** | **Baa3** | **BBB** | **BBB** |
| Southern California Edison Company | | Baa2 | Baa2 | BBB | BBB |
| **Entergy Corporation** | **ETR** | **Baa2** | **Baa2** | **BBB+** | **BBB+** |
| Entergy Arkansas, LLC | | Baa1 | Baa1 | A- | A- |
| Entergy Louisiana, LLC | | Baa1 | Baa1 | A- | A- |
| Entergy Mississippi, LLC | | Baa1 | Baa1 | A- | A- |
| Entergy New Orleans, LLC | | Ba1 | Ba1 | BBB+ | BBB+ |
| Entergy Texas, Inc. | | Baa3 | Baa3 | BBB+ | BBB+ |
| **Evergy, Inc.** | **EVRG** | **Baa2** | **Baa2** | **A-** | **A-** |
| Evergy Kansas Central, Inc. | | Baa1 | Baa1 | A- | A- |
| Evergy Kansas South, Inc. | | Baa1 | Baa1 | A- | A- |
| Evergy Metro, Inc. | | Baa1 | Baa1 | A- | A- |
| Evergy Missouri West, Inc. | | Baa2 | Baa2 | A- | A- |
| **Eversource Energy** | **ES** | **Baa1** | **Baa1** | **A-** | **A-** |
| Connecticut Light and Power Company | | A3 | A3 | A | A |
| NSTAR Electric Company | | A1 | A1 | A | A |
| Public Service Company of New Hampshire | | A3 | A3 | A | A |

Credit Ratings - Dr. Woolridge's Proxy Group

| Company | Ticker | Moody's Long-Term Issuer | Moody's Corporate Long-Term | S&P Long-Term Issuer | S&P Corporate Long-Term |
|---|---|---|---|---|---|
| **Exelon Corporation** | **EXC** | **Baa2** | **Baa2** | **BBB+** | **BBB+** |
| Atlantic City Electric Company | | Baa1 | Baa1 | A- | A- |
| Baltimore Gas and Electric Company | | A3 | A3 | A | A |
| Commonwealth Edison Company | | A3 | A3 | A- | A- |
| Delmarva Power & Light Company | | Baa1 | Baa1 | A- | A- |
| PECO Energy Co. | | A2 | A2 | BBB+ | BBB+ |
| Potomac Electric Power Company | | Baa1 | Baa1 | A- | A- |
| **FirstEnergy Corp.** | **FE** | **Baa3** | **Baa3** | **BBB** | **BBB** |
| Cleveland Electric Illuminating Company | | Baa2 | Baa2 | BBB | BBB |
| Jersey Central Power & Light Company | | Baa1 | Baa1 | BBB | BBB |
| Metropolitan Edison Company | | A3 | A3 | BBB | BBB |
| Monongahela Power Company | | Baa2 | Baa2 | BBB | BBB |
| Ohio Edison Company | | A3 | A3 | BBB | BBB |
| Pennsylvania Electric Company | | Baa1 | Baa1 | BBB | BBB |
| Pennsylvania Power Company | | A3 | A3 | BBB | BBB |
| Potomac Edison Company | | Baa2 | Baa2 | BBB | BBB |
| Toledo Edison Company | | Baa1 | Baa1 | BBB | BBB |
| West Penn Power Company | | A3 | A3 | BBB | BBB |
| **Hawaiian Electric Industries, Inc.** | **HE** | | | **BBB-** | **BBB-** |
| Hawaiian Electric Company, Inc. | | Baa2 | Baa2 | BBB- | BBB- |
| Hawaii Electric Light Company | | | | BBB- | BBB- |
| Maui Electric Company, Ltd | | | | BBB- | BBB- |
| **IDACORP, Inc.** | **IDA** | **Baa1** | **Baa1** | **BBB** | **BBB** |
| Idaho Power Company | | A3 | A3 | BBB | BBB |
| **MGE Energy, Inc.** | **MGEE** | | | | |
| Madison Gas and Electric Company | | A1 | A1 | AA- | AA- |
| **NextEra Energy, Inc.** | **NEE** | **Baa1** | **Baa1** | **A-** | **A-** |
| Florida Power & Light Company | | A1 | A1 | A | A |
| Gulf Power Company | | A2 | A2 | A | A |
| **NorthWestern Corporation** | **NWE** | | **Baa2** | **BBB** | **BBB** |
| **OGE Energy Corp.** | **OGE** | | **(P)Baa1** | **BBB+** | **BBB+** |
| Oklahoma Gas and Electric Company | | A3 | A3 | A- | A- |
| **Otter Tail Corporation** | **OTTR** | **Baa2** | **Baa2** | **BBB** | **BBB** |
| Otter Tail Power Company | | A3 | A3 | BBB+ | BBB+ |
| **Pinnacle West Capital Corporation** | **PNW** | **A3** | **A3** | **A-** | **A-** |
| Arizona Public Service Company | | A2 | A2 | A- | A- |
| **PNM Resources, Inc.** | **PNM** | **Baa3** | **Baa3** | **BBB** | **BBB** |
| Public Service Company of New Mexico | | Baa2 | Baa2 | BBB | BBB |
| Texas-New Mexico Power Company | | A3 | A3 | BBB+ | BBB+ |
| **Portland General Electric Company** | **POR** | **A3** | **A3** | **BBB+** | **BBB+** |
| **PPL Corporation** | **PPL** | **Baa2** | **Baa2** | **A-** | **A-** |
| Kentucky Utilities Company | | A3 | A3 | A- | A- |
| LG&E and KU Energy LLC | | Baa1 | Baa1 | A- | A- |
| Louisville Gas and Electric Company | | A3 | A3 | A- | A- |
| PPL Electric Utilities Corporation | | A3 | A3 | A- | A- |
| **Sempra Energy** | **SRE** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| Oncor Electric Delivery Company LLC | | | A2 | A | A |
| San Diego Gas & Electric Company | | Baa1 | Baa1 | BBB+ | BBB+ |
| **Southern Company** | **SO** | | **Baa2** | **A-** | **A-** |
| Alabama Power Company | | A1 | A1 | A | A |
| Georgia Power Company | | Baa1 | Baa1 | A- | A- |
| Mississippi Power Company | | Baa2 | Baa2 | A- | A- |
| **WEC Energy Group, Inc.** | **WEC** | **Baa1** | **Baa1** | **A-** | **A-** |
| Wisconsin Electric Power Company | | A2 | A2 | A- | A- |
| Wisconsin Public Service Corporation | | A2 | A2 | A- | A- |
| **Xcel Energy Inc.** | **XEL** | **Baa1** | **Baa1** | **A-** | **A-** |
| Northern States Power Company - MN | | A2 | A2 | A- | A- |
| Northern States Power Company - WI | | | (P)A2 | A- | A- |
| Public Service Company of Colorado | | A3 | A3 | A- | A- |
| Southwestern Public Service Company | | Baa2 | Baa2 | A- | A- |

Source: S&P Global Market Intelligence

Hypothetical Example: Flotation Cost Recovery

| | |
|---|---|
| Return on Equity | 10.50% |
| Flotation Costs | 2.69% |
| Market Value | $ 25.00 |
| Dividend Yield | 4.25% |
| Growth Rate | 6.25% |
| Adjusted ROE | 10.62% |
| **Flotation Cost Recovery:** | **No** |
| **DCF Estimate** | **10.38%** |

| | Common Stock | Retained Earnings | Book Value | Market Price | Market/ Book Value | Earnings Per Share | Dividends Per Share | Payout Ratio |
|---|---|---|---|---|---|---|---|---|
| 1 | $ 24.33 | | $ 24.33 | $ 25.00 | 1.0277 | $ 2.55 | $ 1.06 | 41.60% |
| 2 | $ 24.33 | $ 1.49 | $ 25.82 | $ 26.53 | 1.0277 | $ 2.71 | $ 1.13 | 41.60% |
| 3 | $ 24.33 | $ 3.08 | $ 27.40 | $ 28.16 | 1.0277 | $ 2.88 | $ 1.20 | 41.60% |
| 4 | $ 24.33 | $ 4.76 | $ 29.08 | $ 29.89 | 1.0277 | $ 3.05 | $ 1.27 | 41.60% |
| 5 | $ 24.33 | $ 6.54 | $ 30.87 | $ 31.72 | 1.0277 | $ 3.24 | $ 1.35 | 41.60% |
| 6 | $ 24.33 | $ 8.43 | $ 32.76 | $ 33.67 | 1.0277 | $ 3.44 | $ 1.43 | 41.60% |
| 7 | $ 24.33 | $ 10.44 | $ 34.77 | $ 35.73 | 1.0277 | $ 3.65 | $ 1.52 | 41.60% |
| 8 | $ 24.33 | $ 12.57 | $ 36.90 | $ 37.92 | 1.0277 | $ 3.87 | $ 1.61 | 41.60% |
| 9 | $ 24.33 | $ 14.84 | $ 39.16 | $ 40.25 | 1.0277 | $ 4.11 | $ 1.71 | 41.60% |
| 10 | $ 24.33 | $ 17.24 | $ 41.56 | $ 42.71 | 1.0277 | $ 4.36 | $ 1.82 | 41.60% |
| | Growth Rate | | 6.13% | 6.13% | | 6.13% | 6.13% | |

| | |
|---|---|
| Return on Equity | 10.50% |
| Flotation Costs | 2.69% |
| Market Value | $ 25.00 |
| Dividend Yield | 4.25% |
| Growth Rate | 6.25% |
| Adjusted ROE | 10.62% |
| **Flotation Cost Recovery:** | **Yes** |
| **DCF Estimate** | **10.50%** |

| | Common Stock | Retained Earnings | Book Value | Market Price | Market/ Book Value | Earnings Per Share | Dividends Per Share | Payout Ratio |
|---|---|---|---|---|---|---|---|---|
| 1 | $ 24.33 | | $ 24.33 | $ 25.00 | 1.0277 | $ 2.58 | $ 1.06 | 41.14% |
| 2 | $ 24.33 | $ 1.52 | $ 25.85 | $ 26.56 | 1.0277 | $ 2.74 | $ 1.13 | 41.14% |
| 3 | $ 24.33 | $ 3.14 | $ 27.46 | $ 28.22 | 1.0277 | $ 2.92 | $ 1.20 | 41.14% |
| 4 | $ 24.33 | $ 4.85 | $ 29.18 | $ 29.99 | 1.0277 | $ 3.10 | $ 1.27 | 41.14% |
| 5 | $ 24.33 | $ 6.68 | $ 31.00 | $ 31.86 | 1.0277 | $ 3.29 | $ 1.35 | 41.14% |
| 6 | $ 24.33 | $ 8.61 | $ 32.94 | $ 33.85 | 1.0277 | $ 3.50 | $ 1.44 | 41.14% |
| 7 | $ 24.33 | $ 10.67 | $ 35.00 | $ 35.97 | 1.0277 | $ 3.72 | $ 1.53 | 41.14% |
| 8 | $ 24.33 | $ 12.86 | $ 37.19 | $ 38.22 | 1.0277 | $ 3.95 | $ 1.62 | 41.14% |
| 9 | $ 24.33 | $ 15.18 | $ 39.51 | $ 40.60 | 1.0277 | $ 4.20 | $ 1.73 | 41.14% |
| 10 | $ 24.33 | $ 17.65 | $ 41.98 | $ 43.14 | 1.0277 | $ 4.46 | $ 1.83 | 41.14% |
| | Growth Rate | | 6.25% | 6.25% | | 6.25% | 6.25% | |

Dr. Woolridge's Proxy Group Capital Structure - Consolidated

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 57.26% | 58.49% | 58.29% | 59.20% | 58.22% | 58.12% | 58.26% | 57.91% | 58.22% |
| Alliant Energy Corporation | LNT | 44.45% | 43.24% | 45.34% | 45.45% | 44.27% | 44.24% | 46.28% | 46.19% | 44.93% |
| Ameren Corporation | AEE | 47.18% | 47.55% | 47.28% | 47.49% | 48.09% | 46.61% | 47.67% | 47.52% | 47.42% |
| American Electric Power Co. | AEP | 42.00% | 41.85% | 42.65% | 44.60% | 45.50% | 45.94% | 46.27% | 46.00% | 44.35% |
| Avangrid, Inc. | AGR | 68.13% | 69.00% | 71.77% | 72.39% | 72.92% | 72.91% | 73.84% | 73.70% | 71.83% |
| Avista Corporation | AVA | 47.72% | 48.68% | 48.46% | 48.08% | 47.74% | 47.92% | 49.17% | 48.72% | 48.31% |
| CMS Energy Corporation | CMS | 27.24% | 28.04% | 28.66% | 28.93% | 30.32% | 30.65% | 30.71% | 30.09% | 29.33% |
| Consolidated Edison, Inc. | ED | 46.91% | 46.54% | 46.68% | 47.97% | 48.89% | 47.87% | 49.42% | 49.03% | 47.91% |
| Dominion Energy, Inc. | D | 41.58% | 39.80% | 39.97% | 36.59% | 34.36% | 34.00% | 33.75% | 33.50% | 36.69% |
| Duke Energy Corporation | DUK | 42.74% | 42.95% | 43.23% | 44.55% | 44.34% | 44.64% | 44.10% | 44.39% | 43.87% |
| Edison International | EIX | 41.88% | 38.51% | 38.65% | 41.55% | 45.13% | 45.13% | 45.79% | 49.05% | 43.21% |
| Entergy Corporation | ETR | 36.10% | 35.69% | 33.75% | 35.33% | 33.72% | 33.54% | 32.09% | 34.61% | 34.35% |
| Evergy, Inc. | EVRG | 48.39% | 54.82% | 53.99% | 57.30% | 58.99% | 59.19% | NA | 50.40% | 54.72% |
| Eversource Energy | ES | 44.79% | 45.21% | 45.82% | 45.55% | 46.41% | 46.38% | 46.03% | 47.33% | 45.94% |
| Exelon Corporation | EXC | 45.54% | 45.57% | 45.54% | 46.19% | 46.51% | 46.77% | 46.70% | 46.32% | 46.14% |
| FirstEnergy Corporation | FE | 26.62% | 26.94% | 26.43% | 26.98% | 27.72% | 29.99% | 28.73% | 16.94% | 26.29% |
| Hawaiian Electric Industries | HE | 51.16% | 50.63% | 50.09% | 52.91% | 53.77% | 53.40% | 54.66% | 54.75% | 52.67% |
| IDACORP, Inc. | IDA | 57.30% | 56.70% | 56.47% | 56.37% | 56.35% | 55.56% | 53.48% | 56.32% | 56.07% |
| MGE Energy, Inc. | MGEE | 62.36% | 61.80% | 61.65% | 62.04% | 61.94% | 65.38% | 65.12% | 64.81% | 63.14% |
| NextEra Energy, Inc. | NEE | 48.39% | 48.80% | 51.30% | 53.48% | 53.56% | 52.42% | 52.81% | 45.88% | 50.83% |
| NorthWestern Corporation | NWE | 47.67% | 47.94% | 48.59% | 47.76% | 48.24% | 48.28% | 47.34% | 49.74% | 48.19% |
| OGE Energy Corp. | OGE | 56.36% | 55.28% | 57.44% | 56.00% | 56.15% | 56.46% | 56.16% | 56.22% | 56.26% |
| Otter Tail Corporation | OTTR | 55.26% | 54.95% | 54.78% | 55.26% | 55.14% | 54.77% | 54.54% | 58.69% | 55.42% |
| Pinnacle West Capital Corp. | PNW | 50.18% | 49.92% | 49.98% | 50.41% | 51.27% | 51.22% | 50.74% | 50.68% | 50.55% |
| PNM Resources, Inc. | PNM | 35.82% | 35.57% | 35.23% | 38.74% | 40.39% | 39.91% | 39.47% | 41.02% | 38.27% |
| Portland General Electric Company | POR | 49.82% | 49.72% | 50.27% | 50.28% | 50.60% | 50.40% | 50.24% | 49.90% | 50.15% |
| PPL Corporation | PPL | 35.49% | 36.12% | 36.25% | 36.14% | 36.78% | 35.50% | 35.32% | 34.76% | 35.80% |
| Sempra Energy | SRE | 41.40% | 38.85% | 40.20% | 39.71% | 39.56% | 38.70% | 38.37% | 41.48% | 39.78% |
| Southern Company | SO | 36.80% | 37.54% | 37.15% | 36.01% | 35.89% | 34.58% | 34.10% | 33.32% | 35.67% |
| WEC Energy Group | WEC | 46.35% | 48.28% | 48.18% | 48.59% | 50.74% | 50.58% | 50.24% | 49.67% | 49.08% |
| Xcel Energy Inc. | XEL | 40.20% | 40.11% | 40.79% | 42.99% | 43.09% | 41.88% | 43.56% | 43.34% | 42.00% |
| Mean | | 45.91% | 45.97% | 46.29% | 46.93% | 47.31% | 47.19% | 46.83% | 46.85% | 46.69% |

Dr. Woolridge's Proxy Group Capital Structure - Consolidated

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 42.74% | 41.51% | 41.71% | 40.80% | 41.78% | 41.88% | 41.74% | 42.09% | 41.78% |
| Alliant Energy Corporation | LNT | 55.55% | 56.76% | 54.66% | 54.55% | 55.73% | 55.76% | 53.72% | 53.81% | 55.07% |
| Ameren Corporation | AEE | 52.82% | 52.45% | 52.72% | 52.51% | 51.91% | 53.39% | 52.33% | 52.48% | 52.58% |
| American Electric Power Co. | AEP | 58.00% | 58.15% | 57.35% | 55.40% | 54.50% | 54.06% | 53.73% | 54.00% | 55.65% |
| Avangrid, Inc. | AGR | 31.87% | 31.00% | 28.23% | 27.61% | 27.08% | 27.09% | 26.16% | 26.30% | 28.17% |
| Avista Corporation | AVA | 52.28% | 51.32% | 51.54% | 51.92% | 52.26% | 52.08% | 50.83% | 51.28% | 51.69% |
| CMS Energy Corporation | CMS | 72.76% | 71.96% | 71.34% | 71.07% | 69.68% | 69.35% | 69.29% | 69.91% | 70.67% |
| Consolidated Edison, Inc. | ED | 53.09% | 53.46% | 53.32% | 52.03% | 51.11% | 52.13% | 50.58% | 50.97% | 52.09% |
| Dominion Energy, Inc. | D | 58.42% | 60.20% | 60.03% | 63.41% | 65.64% | 66.00% | 66.25% | 66.50% | 63.31% |
| Duke Energy Corporation | DUK | 57.26% | 57.05% | 56.77% | 55.45% | 55.66% | 55.36% | 55.90% | 55.61% | 56.13% |
| Edison International | EIX | 58.12% | 61.49% | 61.35% | 58.45% | 54.87% | 54.87% | 54.21% | 50.95% | 56.79% |
| Entergy Corporation | ETR | 63.90% | 64.31% | 66.25% | 64.67% | 66.28% | 66.46% | 67.91% | 65.39% | 65.65% |
| Evergy, Inc. | EVRG | 51.61% | 45.18% | 46.01% | 42.70% | 41.01% | 40.81% | NA | 49.60% | 45.28% |
| Eversource Energy | ES | 55.21% | 54.79% | 54.18% | 54.45% | 53.59% | 53.62% | 53.97% | 52.67% | 54.06% |
| Exelon Corporation | EXC | 54.46% | 54.43% | 54.46% | 53.81% | 53.49% | 53.23% | 53.30% | 53.68% | 53.86% |
| FirstEnergy Corporation | FE | 73.38% | 73.06% | 73.57% | 73.02% | 72.28% | 70.01% | 71.27% | 83.06% | 73.71% |
| Hawaiian Electric Industries | HE | 48.84% | 49.37% | 49.91% | 47.09% | 46.23% | 46.60% | 45.34% | 45.25% | 47.33% |
| IDACORP, Inc. | IDA | 42.70% | 43.30% | 43.53% | 43.63% | 43.65% | 44.44% | 46.52% | 43.68% | 43.93% |
| MGE Energy, Inc. | MGEE | 37.64% | 38.20% | 38.35% | 37.96% | 38.06% | 34.62% | 34.88% | 35.19% | 36.86% |
| NextEra Energy, Inc. | NEE | 51.61% | 51.20% | 48.70% | 46.52% | 46.44% | 47.58% | 47.19% | 54.12% | 49.17% |
| NorthWestern Corporation | NWE | 52.33% | 52.06% | 51.41% | 52.24% | 51.76% | 51.72% | 52.66% | 50.26% | 51.81% |
| OGE Energy Corp. | OGE | 43.64% | 44.72% | 42.56% | 44.00% | 43.85% | 43.54% | 43.84% | 43.78% | 43.74% |
| Otter Tail Corporation | OTTR | 44.74% | 45.05% | 45.22% | 44.74% | 44.86% | 45.23% | 45.46% | 41.31% | 44.58% |
| Pinnacle West Capital Corp. | PNW | 49.82% | 50.08% | 50.02% | 49.59% | 48.73% | 48.78% | 49.26% | 49.32% | 49.45% |
| PNM Resources, Inc. | PNM | 64.18% | 64.43% | 64.77% | 61.26% | 59.61% | 60.09% | 60.53% | 58.98% | 61.73% |
| Portland General Electric Company | POR | 50.18% | 50.28% | 49.73% | 49.72% | 49.40% | 49.60% | 49.76% | 50.10% | 49.85% |
| PPL Corporation | PPL | 64.51% | 63.88% | 63.75% | 63.86% | 63.22% | 64.50% | 64.68% | 65.24% | 64.20% |
| Sempra Energy | SRE | 58.60% | 61.15% | 59.80% | 60.29% | 60.44% | 61.30% | 61.63% | 58.52% | 60.22% |
| Southern Company | SO | 63.20% | 62.46% | 62.85% | 63.99% | 64.11% | 65.42% | 65.90% | 66.68% | 64.33% |
| WEC Energy Group | WEC | 53.65% | 51.72% | 51.82% | 51.41% | 49.26% | 49.42% | 49.76% | 50.33% | 50.92% |
| Xcel Energy Inc. | XEL | 59.80% | 59.89% | 59.21% | 57.01% | 56.91% | 58.12% | 56.44% | 56.66% | 58.00% |
| Mean | | 54.09% | 54.03% | 53.71% | 53.07% | 52.69% | 52.81% | 53.17% | 53.15% | 53.31% |

Dr. Woolridge's Proxy Group Capital Structure - Operating Company Level

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 58.68% | 59.66% | 59.53% | 59.12% | 58.50% | 58.84% | 63.09% | 62.51% | 59.99% |
| Alliant Energy Corporation | LNT | 51.73% | 50.38% | 53.18% | 53.11% | 51.13% | 51.00% | 49.74% | 49.77% | 51.26% |
| Ameren Corporation | AEE | 53.67% | 53.03% | 52.81% | 52.69% | 53.22% | 52.01% | 53.04% | 52.65% | 52.89% |
| American Electric Power Co. | AEP | 49.91% | 48.80% | 49.62% | 49.40% | 48.68% | 48.52% | 48.60% | 48.91% | 49.06% |
| Avangrid, Inc. | AGR | 54.38% | 56.33% | 56.51% | 55.72% | 56.13% | 54.93% | 56.55% | 55.69% | 55.78% |
| Avista Corporation | AVA | 55.80% | 56.32% | 56.10% | 55.09% | 55.75% | 55.76% | 56.34% | 55.76% | 55.86% |
| CMS Energy Corporation | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison, Inc. | ED | 49.85% | 49.08% | 48.75% | 47.97% | 48.38% | 48.73% | 49.75% | 49.23% | 48.97% |
| Dominion Energy, Inc. | D | 53.56% | 50.98% | 50.47% | 48.75% | 51.63% | 51.12% | 50.17% | 50.62% | 50.91% |
| Duke Energy Corporation | DUK | 52.89% | 54.48% | 53.14% | 54.35% | 55.03% | 54.94% | 54.46% | 54.30% | 54.20% |
| Edison International | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Corporation | ETR | 49.10% | 48.19% | 48.81% | 50.11% | 49.96% | 49.95% | 48.60% | 48.97% | 49.21% |
| Evergy, Inc. | EVRG | 60.28% | 60.51% | 58.16% | 59.56% | 59.86% | 58.51% | 58.73% | 58.62% | 59.28% |
| Eversource Energy | ES | 49.53% | 49.38% | 54.22% | 53.28% | 51.03% | 50.14% | 54.05% | 54.60% | 52.03% |
| Exelon Corporation | EXC | 51.77% | 52.46% | 52.41% | 51.93% | 51.85% | 52.40% | 52.25% | 52.10% | 52.15% |
| FirstEnergy Corporation | FE | 55.88% | 55.95% | 56.46% | 56.61% | 58.05% | 57.49% | 56.37% | 55.73% | 56.57% |
| Hawaiian Electric Industries | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| IDACORP, Inc. | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| MGE Energy, Inc. | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| NextEra Energy, Inc. | NEE | 56.15% | 61.22% | 61.05% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 61.20% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| OGE Energy Corp. | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Corporation | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Pinnacle West Capital Corp. | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| PNM Resources, Inc. | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| PPL Corporation | PPL | 53.84% | 53.74% | 55.38% | 55.06% | 54.92% | 54.59% | 54.52% | 54.67% | 54.59% |
| Sempra Energy | SRE | 56.17% | 56.30% | 53.82% | 53.29% | 53.13% | 54.39% | 54.20% | 53.27% | 54.32% |
| Southern Company | SO | 52.36% | 52.93% | 52.80% | 54.21% | 51.50% | 50.31% | 49.98% | 47.67% | 51.47% |
| WEC Energy Group | WEC | 55.79% | 56.71% | 55.73% | 53.46% | 58.30% | 57.72% | 61.62% | 54.62% | 56.74% |
| Xcel Energy Inc. | XEL | 53.98% | 54.70% | 54.51% | 54.22% | 53.37% | 53.63% | 54.15% | 53.95% | 54.06% |
| Mean | | 53.55% | 53.55% | 53.50% | 53.37% | 53.64% | 53.39% | 53.66% | 53.54% | 53.52% |

Operating Company Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 59.33% | 60.94% | 60.87% | 61.39% | 60.43% | 60.33% | 60.38% | 60.04% | 60.46% |
| Superior Water, Light and Power Company | ALE | 58.03% | 58.38% | 58.19% | 56.86% | 56.58% | 57.34% | 65.80% | 64.99% | 59.52% |
| Interstate Power and Light Company | LNT | 50.06% | 51.76% | 53.33% | 53.52% | 49.64% | 50.47% | 49.92% | 50.31% | 51.13% |
| Wisconsin Power and Light Company | LNT | 53.40% | 49.01% | 53.03% | 52.69% | 52.62% | 51.52% | 49.57% | 49.23% | 51.38% |
| Ameren Illinois Company | AEE | 54.46% | 54.05% | 53.65% | 52.86% | 53.18% | 52.74% | 54.24% | 53.38% | 53.57% |
| Union Electric Company | AEE | 52.88% | 52.00% | 51.96% | 52.52% | 53.26% | 51.28% | 51.84% | 51.92% | 52.21% |
| AEP Texas Inc. | AEP | 46.97% | 46.32% | 47.54% | 45.38% | 43.80% | 43.20% | 46.75% | 45.14% | 45.64% |
| Appalachian Power Company | AEP | 48.74% | 48.19% | 47.77% | 49.51% | 49.30% | 48.93% | 49.35% | 48.72% | 48.81% |
| Indiana Michigan Power Company | AEP | 46.51% | 45.83% | 45.43% | 44.62% | 44.53% | 44.15% | 46.64% | 46.33% | 45.50% |
| Kentucky Power Company | AEP | 46.94% | 46.50% | 46.42% | 45.72% | 45.28% | 44.89% | 44.40% | 43.52% | 45.46% |
| Kingsport Power Company | AEP | 54.24% | 50.18% | 51.54% | 50.79% | 50.71% | 47.69% | 47.28% | 46.53% | 49.87% |
| Ohio Power Company | AEP | 53.63% | 52.92% | 58.86% | 57.80% | 56.85% | 57.11% | 52.91% | 58.63% | 56.09% |
| Public Service Company of Oklahoma | AEP | 49.89% | 48.02% | 47.19% | 49.16% | 49.55% | 48.59% | 48.10% | 48.50% | 48.62% |
| Southwestern Electric Power Company | AEP | 48.63% | 47.45% | 47.59% | 46.97% | 43.43% | 47.91% | 47.72% | 48.52% | 47.28% |
| Wheeling Power Company | AEP | 53.66% | 53.83% | 54.27% | 54.62% | 54.70% | 54.19% | 54.27% | 54.26% | 54.23% |
| Central Maine Power Company | AGR | 62.19% | 61.96% | 63.51% | 63.21% | 64.17% | 63.53% | 64.18% | 63.82% | 63.32% |
| New York State Electric & Gas Corporation | AGR | 48.79% | 55.84% | 55.93% | 54.30% | 53.95% | 50.99% | 54.51% | 53.30% | 53.45% |
| Rochester Gas and Electric Corporation | AGR | 50.50% | 50.25% | 49.96% | 48.89% | 48.16% | 47.77% | 50.80% | 49.63% | 49.50% |
| United Illuminating Company | AGR | 56.05% | 57.26% | 56.65% | 56.46% | 58.23% | 57.43% | 56.70% | 56.00% | 56.85% |
| Alaska Electric Light and Power Company | AVA | 61.28% | 61.24% | 61.02% | 60.29% | 61.94% | 61.78% | 61.53% | 60.77% | 61.23% |
| Avista Corporation | AVA | 50.33% | 51.40% | 51.18% | 49.89% | 49.55% | 49.74% | 51.16% | 50.75% | 50.50% |
| Consumers Energy Company | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison Company of New York, Inc. | ED | 49.29% | 48.92% | 48.30% | 47.52% | 48.33% | 46.72% | 48.66% | 48.22% | 48.24% |
| Orange and Rockland Utilities, Inc. | ED | 50.40% | 49.25% | 49.21% | 48.41% | 48.44% | 50.74% | 50.83% | 50.25% | 49.69% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 53.33% | 53.30% | 52.42% | 52.62% | 53.64% | 52.81% | 51.03% | 51.71% | 52.61% |
| Dominion Energy South Carolina, Inc. | D | 53.80% | 48.67% | 48.52% | 44.88% | 49.63% | 49.44% | 49.30% | 49.54% | 49.22% |
| Duke Energy Carolinas, LLC | DUK | 51.80% | 52.94% | 52.32% | 51.78% | 52.64% | 52.10% | 51.70% | 52.98% | 52.28% |
| Duke Energy Florida, LLC | DUK | 52.82% | 51.55% | 50.56% | 50.04% | 49.65% | 48.79% | 49.92% | 49.25% | 50.32% |
| Duke Energy Indiana, LLC | DUK | 51.52% | 54.83% | 54.29% | 53.26% | 52.79% | 52.64% | 52.54% | 51.94% | 52.98% |
| Duke Energy Kentucky, Inc. | DUK | 45.44% | 53.04% | 52.81% | 51.95% | 56.58% | 55.79% | 53.72% | 53.11% | 52.80% |
| Duke Energy Ohio, Inc. | DUK | 64.90% | 64.45% | 59.29% | 68.09% | 67.73% | 67.10% | 66.06% | 66.24% | 65.48% |
| Duke Energy Progress, LLC | DUK | 50.86% | 50.09% | 49.60% | 51.00% | 50.76% | 53.22% | 52.82% | 52.27% | 51.33% |
| Southern California Edison Company | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Arkansas, LLC | ETR | 47.72% | 46.49% | 47.04% | 49.42% | 49.38% | 48.29% | 45.88% | 45.95% | 47.52% |
| Entergy Louisiana, LLC | ETR | 47.13% | 46.32% | 45.79% | 47.37% | 46.77% | 46.97% | 44.58% | 47.43% | 46.55% |
| Entergy Mississippi, LLC | ETR | 48.35% | 44.93% | 49.41% | 49.11% | 50.10% | 49.10% | 48.32% | 47.85% | 48.40% |
| Entergy New Orleans, LLC | ETR | 53.69% | 52.40% | 51.69% | 51.19% | 50.93% | 54.02% | 53.43% | 53.16% | 52.56% |
| Entergy Texas, Inc. | ETR | 48.63% | 50.79% | 50.13% | 53.46% | 52.61% | 51.38% | 50.79% | 50.45% | 51.03% |
| Evergy Kansas South, Inc. | EVRG | 81.84% | 81.49% | 75.13% | 74.97% | 74.91% | 74.45% | 74.29% | 74.18% | 76.41% |
| Evergy Metro, Inc. | EVRG | 50.43% | 49.62% | 46.04% | 49.49% | 49.50% | 48.88% | 49.25% | 49.15% | 49.05% |
| Evergy Missouri West, Inc. | EVRG | 51.18% | 51.74% | 52.68% | 54.71% | 55.70% | 52.03% | 52.63% | 52.40% | 52.88% |
| Westar Energy (KPL) | EVRG | 57.66% | 59.18% | 58.80% | 59.08% | 59.34% | 58.68% | 58.75% | 58.74% | 58.78% |
| Connecticut Light and Power Company | ES | 54.12% | 55.38% | 58.18% | 56.18% | 54.49% | 53.85% | 50.40% | 53.82% | 54.55% |
| NSTAR Electric Company | ES | 53.81% | 52.74% | 56.08% | 55.74% | 55.50% | 54.51% | 53.83% | 53.85% | 54.51% |
| Public Service Company of New Hampshire | ES | 40.64% | 40.02% | 48.38% | 47.92% | 43.11% | 42.06% | 57.93% | 57.30% | 47.17% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 53.43% | 53.43% |
| Atlantic City Electric Company | EXC | 49.38% | 49.47% | 49.30% | 49.14% | 50.38% | 49.46% | 49.14% | 49.19% | 49.43% |
| Baltimore Gas and Electric Company | EXC | 51.89% | 54.36% | 54.43% | 53.67% | 52.85% | 55.34% | 55.36% | 54.77% | 54.08% |
| Commonwealth Edison Company | EXC | 55.61% | 55.29% | 55.00% | 55.06% | 54.72% | 55.36% | 54.96% | 54.85% | 55.11% |
| Delmarva Power & Light Company | EXC | 50.18% | 50.20% | 50.18% | 49.98% | 50.11% | 49.86% | 50.35% | 50.38% | 50.16% |
| PECO Energy Co. | EXC | 53.37% | 55.20% | 55.13% | 53.72% | 52.82% | 54.28% | 53.77% | 53.54% | 53.98% |
| Potomac Electric Power Company | EXC | 50.21% | 50.24% | 50.41% | 50.01% | 50.24% | 50.08% | 49.94% | 49.89% | 50.13% |
| Cleveland Electric Illuminating Company | FE | 55.74% | 55.49% | 55.54% | 55.44% | 56.50% | 56.31% | 55.48% | 55.27% | 55.72% |
| Jersey Central Power & Light Company | FE | 68.74% | 68.23% | 68.08% | 69.46% | 69.34% | 68.81% | 65.52% | 65.30% | 67.93% |
| Metropolitan Edison Company | FE | 49.72% | 48.46% | 47.78% | 53.21% | 54.25% | 53.10% | 52.18% | 52.33% | 51.38% |
| Monongahela Power Company | FE | 49.98% | 49.07% | 49.05% | 48.87% | 50.71% | 51.53% | 50.57% | 49.15% | 49.87% |
| Ohio Edison Company | FE | 69.16% | 71.42% | 70.82% | 69.93% | 69.14% | 67.33% | 66.89% | 64.91% | 68.70% |
| Pennsylvania Electric Company | FE | 51.78% | 50.93% | 53.85% | 53.89% | 54.01% | 53.90% | 53.09% | 52.06% | 52.94% |
| Pennsylvania Power Company | FE | 53.09% | 51.71% | 50.69% | 49.03% | 58.27% | 56.89% | 55.70% | 53.82% | 53.65% |
| Potomac Edison Company | FE | 53.69% | 52.99% | 53.29% | 52.35% | 52.92% | 52.65% | 52.64% | 51.59% | 52.77% |
| Toledo Edison Company | FE | 60.76% | 60.57% | 60.78% | 60.43% | 62.25% | 62.25% | 60.60% | 60.04% | 60.96% |
| West Penn Power Company | FE | 46.11% | 50.63% | 54.68% | 53.50% | 53.14% | 52.09% | 51.09% | 52.82% | 51.76% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| Madison Gas and Electric Company | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| Florida Power & Light Company | NEE | 59.78% | 61.30% | 64.03% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 62.03% |
| Gulf Power Company | NEE | 52.52% | 61.15% | 58.06% | NA | NA | NA | NA | NA | 57.24% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| Oklahoma Gas and Electric Company | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Power Company | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Arizona Public Service Company | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| Public Service Company of New Mexico | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Kentucky Utilities Company | PPL | 52.97% | 52.81% | 55.44% | 54.85% | 54.76% | 54.51% | 54.08% | 54.00% | 54.18% |
| Louisville Gas and Electric Company | PPL | 54.10% | 53.88% | 56.16% | 55.80% | 55.35% | 54.97% | 54.46% | 55.42% | 55.02% |
| PPL Electric Utilities Corporation | PPL | 54.44% | 54.51% | 54.52% | 54.52% | 54.65% | 54.28% | 55.04% | 54.57% | 54.57% |
| Oncor Electric Delivery Company LLC | SRE | 54.91% | 57.43% | 59.79% | 59.47% | 59.29% | 62.31% | 60.34% | 58.86% | 59.05% |
| San Diego Gas & Electric Company | SRE | 57.43% | 55.17% | 56.60% | 55.79% | 55.17% | 54.47% | 55.92% | 55.09% | 55.71% |
| Sharyland Utilities, LLC | SRE | NA | NA | 45.05% | 44.62% | 44.92% | 46.39% | 46.34% | 45.86% | 45.53% |
| Alabama Power Company | SO | 51.45% | 52.54% | 52.23% | 47.77% | 48.13% | 47.51% | 48.86% | 47.07% | 49.44% |
| Georgia Power Company | SO | 55.38% | 56.39% | 56.43% | 59.02% | 57.27% | 54.97% | 53.81% | 50.06% | 55.42% |
| Mississippi Power Company | SO | 50.23% | 49.87% | 49.73% | 50.35% | 45.28% | 43.87% | 43.00% | 39.34% | 46.46% |
| Gulf Power Company | SO | NA | NA | NA | 59.73% | 55.34% | 54.90% | 54.27% | 54.19% | 55.69% |
| Upper Michigan Energy Resources Corporation | WEC | 56.09% | 54.45% | 52.54% | 47.01% | 55.08% | 54.53% | 70.04% | 49.85% | 54.95% |
| Wisconsin Electric Power Company | WEC | 56.92% | 56.64% | 55.78% | 56.03% | 59.25% | 59.09% | 56.47% | 55.94% | 57.01% |
| Wisconsin Public Service Corporation | WEC | 54.37% | 59.04% | 58.88% | 57.33% | 60.59% | 59.53% | 58.35% | 58.06% | 58.27% |
| Northern States Power Company - MN | XEL | 51.79% | 53.66% | 53.64% | 52.81% | 52.64% | 52.61% | 52.59% | 52.38% | 52.77% |
| Northern States Power Company - WI | XEL | 53.56% | 53.49% | 53.59% | 53.60% | 48.45% | 53.85% | 53.79% | 53.36% | 52.96% |
| Public Service Company of Colorado | XEL | 56.35% | 57.53% | 56.68% | 56.31% | 56.08% | 54.17% | 56.67% | 56.50% | 56.29% |
| Southwestern Public Service Company | XEL | 54.21% | 54.14% | 54.13% | 54.17% | 56.29% | 53.88% | 53.54% | 53.55% | 54.24% |
| Mean | | 53.41% | 53.55% | 53.64% | 53.51% | 53.69% | 53.41% | 53.60% | 53.23% | 53.52% |

Source: S&P Global Market Intelligence

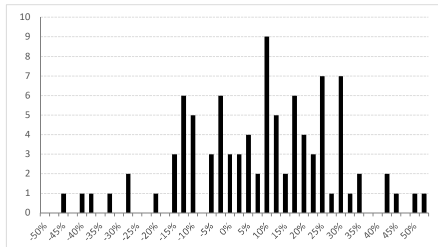
Dr. Woolridge's Proxy Group Capital Structure - Operating Company Level

| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | % Long-Term Debt 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 41.32% | 40.34% | 40.47% | 40.88% | 41.50% | 41.16% | 36.91% | 37.49% | 40.01% |
| Alliant Energy Corporation | LNT | 48.27% | 49.62% | 46.82% | 46.89% | 48.87% | 49.00% | 50.26% | 50.23% | 48.74% |
| Ameren Corporation | AEE | 46.33% | 46.97% | 47.19% | 47.31% | 46.78% | 47.99% | 46.96% | 47.35% | 47.11% |
| American Electric Power Co. | AEP | 50.09% | 51.20% | 50.38% | 50.60% | 51.32% | 51.48% | 51.40% | 51.09% | 50.94% |
| Avangrid, Inc. | AGR | 45.62% | 43.67% | 43.49% | 44.28% | 43.87% | 45.07% | 43.45% | 44.31% | 44.22% |
| Avista Corporation | AVA | 44.20% | 43.68% | 43.90% | 44.91% | 44.25% | 44.24% | 43.66% | 44.24% | 44.14% |
| CMS Energy Corporation | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison, Inc. | ED | 50.15% | 50.92% | 51.25% | 52.03% | 51.62% | 51.27% | 50.25% | 50.77% | 51.03% |
| Dominion Energy, Inc. | D | 46.44% | 49.02% | 49.53% | 51.25% | 48.37% | 48.88% | 49.83% | 49.38% | 49.09% |
| Duke Energy Corporation | DUK | 47.11% | 45.52% | 46.86% | 45.65% | 44.97% | 45.06% | 45.54% | 45.70% | 45.80% |
| Edison International | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Corporation | ETR | 50.90% | 51.81% | 51.19% | 49.89% | 50.04% | 50.05% | 51.40% | 51.03% | 50.79% |
| Evergy, Inc. | EVRG | 39.72% | 39.49% | 41.84% | 40.44% | 40.14% | 41.49% | 41.27% | 41.38% | 40.72% |
| Eversource Energy | ES | 50.47% | 50.62% | 45.78% | 46.72% | 48.97% | 49.86% | 45.95% | 45.40% | 47.97% |
| Exelon Corporation | EXC | 48.23% | 47.54% | 47.59% | 48.07% | 48.15% | 47.60% | 47.75% | 47.90% | 47.85% |
| FirstEnergy Corporation | FE | 44.12% | 44.05% | 43.54% | 43.39% | 41.95% | 42.51% | 43.63% | 44.27% | 43.43% |
| Hawaiian Electric Industries | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| IDACORP, Inc. | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| MGE Energy, Inc. | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| NextEra Energy, Inc. | NEE | 43.85% | 38.78% | 38.95% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 38.80% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| OGE Energy Corp. | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Corporation | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Pinnacle West Capital Corp. | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| PNM Resources, Inc. | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| PPL Corporation | PPL | 46.16% | 46.26% | 44.62% | 44.94% | 45.08% | 45.41% | 45.48% | 45.33% | 45.41% |
| Sempra Energy | SRE | 43.83% | 43.70% | 46.18% | 46.71% | 46.87% | 45.61% | 45.80% | 46.73% | 45.68% |
| Southern Company | SO | 47.64% | 47.07% | 47.20% | 45.79% | 48.50% | 49.69% | 50.02% | 52.33% | 48.53% |
| WEC Energy Group | WEC | 44.21% | 43.29% | 44.27% | 46.54% | 41.70% | 42.28% | 38.38% | 45.38% | 43.26% |
| Xcel Energy Inc. | XEL | 46.02% | 45.30% | 45.49% | 45.78% | 46.63% | 46.37% | 45.85% | 46.05% | 45.94% |
| Mean | | 46.45% | 46.45% | 46.50% | 46.63% | 46.36% | 46.61% | 46.34% | 46.46% | 46.48% |

Operating Company Capital Structure

| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | % Long-Term Debt 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE (Minnesota Power) | ALE | 40.67% | 39.06% | 39.13% | 38.61% | 39.57% | 39.67% | 39.62% | 39.96% | 39.54% |
| Superior Water, Light and Power Company | ALE | 41.97% | 41.62% | 41.81% | 43.14% | 43.42% | 42.66% | 34.20% | 35.01% | 40.48% |
| Interstate Power and Light Company | LNT | 49.94% | 48.24% | 46.67% | 46.48% | 50.36% | 49.53% | 50.08% | 49.69% | 48.87% |
| Wisconsin Power and Light Company | LNT | 46.60% | 50.99% | 46.97% | 47.31% | 47.38% | 48.48% | 50.43% | 50.77% | 48.62% |
| Ameren Illinois Company | AEE | 45.54% | 45.95% | 46.35% | 47.14% | 46.82% | 47.26% | 45.76% | 46.62% | 46.43% |
| Union Electric Company | AEE | 47.12% | 48.00% | 48.04% | 47.48% | 46.74% | 48.72% | 48.16% | 48.08% | 47.79% |
| AEP Texas Inc. | AEP | 53.03% | 53.68% | 52.46% | 54.62% | 56.20% | 56.80% | 53.25% | 54.86% | 54.36% |
| Appalachian Power Company | AEP | 51.26% | 51.81% | 52.23% | 50.49% | 50.70% | 51.07% | 50.65% | 51.28% | 51.19% |
| Indiana Michigan Power Company | AEP | 53.49% | 54.17% | 54.57% | 55.38% | 55.47% | 55.85% | 53.36% | 53.67% | 54.50% |
| Kentucky Power Company | AEP | 53.06% | 53.50% | 53.58% | 54.28% | 54.72% | 55.11% | 55.60% | 56.48% | 54.54% |
| Kingsport Power Company | AEP | 45.76% | 49.82% | 48.46% | 49.21% | 49.29% | 52.31% | 52.72% | 53.47% | 50.13% |
| Ohio Power Company | AEP | 46.37% | 47.08% | 41.14% | 42.20% | 43.15% | 42.89% | 47.09% | 41.37% | 43.91% |
| Public Service Company of Oklahoma | AEP | 50.11% | 51.98% | 52.81% | 50.84% | 50.45% | 51.41% | 51.90% | 51.50% | 51.38% |
| Southwestern Electric Power Company | AEP | 51.37% | 52.55% | 52.41% | 53.03% | 56.57% | 52.09% | 52.28% | 51.48% | 52.72% |
| Wheeling Power Company | AEP | 46.34% | 46.17% | 45.73% | 45.38% | 45.30% | 45.81% | 45.73% | 45.74% | 45.77% |
| Central Maine Power Company | AGR | 37.81% | 38.04% | 36.49% | 36.79% | 35.83% | 36.47% | 35.82% | 36.18% | 36.68% |
| New York State Electric & Gas Corporation | AGR | 51.21% | 44.16% | 44.07% | 45.70% | 46.05% | 49.01% | 45.49% | 46.70% | 46.55% |
| Rochester Gas and Electric Corporation | AGR | 49.50% | 49.75% | 50.04% | 51.11% | 51.84% | 52.23% | 49.20% | 50.37% | 50.50% |
| United Illuminating Company | AGR | 43.95% | 42.74% | 43.35% | 43.54% | 41.77% | 42.57% | 43.30% | 44.00% | 43.15% |
| Alaska Electric Light and Power Company | AVA | 38.72% | 38.76% | 38.98% | 39.71% | 38.06% | 38.22% | 38.47% | 39.23% | 38.77% |
| Avista Corporation | AVA | 49.67% | 48.60% | 48.82% | 50.11% | 50.45% | 50.26% | 48.84% | 49.25% | 49.50% |
| Consumers Energy Company | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison Company of New York, Inc. | ED | 50.71% | 51.08% | 51.70% | 52.48% | 51.67% | 53.28% | 51.34% | 51.78% | 51.76% |
| Orange and Rockland Utilities, Inc. | ED | 49.60% | 50.75% | 50.79% | 51.59% | 51.56% | 49.26% | 49.17% | 49.75% | 50.31% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 46.67% | 46.70% | 47.58% | 47.38% | 46.36% | 47.19% | 48.97% | 48.29% | 47.39% |
| Dominion Energy South Carolina, Inc. | D | 46.20% | 51.33% | 51.48% | 55.12% | 50.37% | 50.56% | 50.70% | 50.46% | 50.78% |
| Duke Energy Carolinas, LLC | DUK | 48.20% | 47.06% | 47.68% | 48.22% | 47.36% | 47.90% | 48.30% | 47.02% | 47.72% |
| Duke Energy Florida, LLC | DUK | 47.18% | 48.45% | 49.44% | 49.96% | 50.35% | 51.21% | 50.08% | 50.75% | 49.68% |
| Duke Energy Indiana, LLC | DUK | 48.48% | 45.17% | 45.71% | 46.74% | 47.21% | 47.36% | 47.46% | 48.06% | 47.02% |
| Duke Energy Kentucky, Inc. | DUK | 54.56% | 46.96% | 47.19% | 48.05% | 43.42% | 44.21% | 46.28% | 46.89% | 47.20% |
| Duke Energy Ohio, Inc. | DUK | 35.10% | 35.55% | 40.71% | 31.91% | 32.27% | 32.90% | 33.94% | 33.76% | 34.52% |
| Duke Energy Progress, LLC | DUK | 49.14% | 49.91% | 50.40% | 49.00% | 49.24% | 46.78% | 47.18% | 47.73% | 48.67% |
| Southern California Edison Company | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Arkansas, LLC | ETR | 52.28% | 53.51% | 52.96% | 50.58% | 50.62% | 51.71% | 54.12% | 54.05% | 52.48% |
| Entergy Louisiana, LLC | ETR | 52.87% | 53.68% | 54.21% | 52.63% | 53.23% | 53.03% | 55.42% | 52.57% | 53.45% |
| Entergy Mississippi, LLC | ETR | 51.65% | 55.07% | 50.59% | 50.89% | 49.90% | 50.90% | 51.68% | 52.15% | 51.60% |
| Entergy New Orleans, LLC | ETR | 46.31% | 47.60% | 48.31% | 48.81% | 49.07% | 45.98% | 46.57% | 46.84% | 47.44% |
| Entergy Texas, Inc. | ETR | 51.37% | 49.21% | 49.87% | 46.54% | 47.39% | 48.62% | 49.21% | 49.55% | 48.97% |
| Evergy Kansas South, Inc. | EVRG | 18.16% | 18.51% | 24.87% | 25.03% | 25.09% | 25.55% | 25.71% | 25.82% | 23.59% |
| Evergy Metro, Inc. | EVRG | 49.57% | 50.38% | 53.96% | 50.51% | 50.50% | 51.12% | 50.75% | 50.85% | 50.95% |
| Evergy Missouri West, Inc. | EVRG | 48.82% | 48.26% | 47.32% | 45.29% | 44.30% | 47.97% | 47.37% | 47.60% | 47.12% |
| Westar Energy (KPL) | EVRG | 42.34% | 40.82% | 41.20% | 40.92% | 40.66% | 41.32% | 41.25% | 41.26% | 41.22% |
| Connecticut Light and Power Company | ES | 45.88% | 44.62% | 41.82% | 43.82% | 45.51% | 46.15% | 49.60% | 46.18% | 45.45% |
| NSTAR Electric Company | ES | 46.19% | 47.26% | 43.92% | 44.26% | 44.50% | 45.49% | 46.17% | 46.15% | 45.49% |
| Public Service Company of New Hampshire | ES | 59.36% | 59.98% | 51.62% | 52.08% | 56.89% | 57.94% | 42.07% | 42.70% | 52.83% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 46.57% | 46.57% |
| Atlantic City Electric Company | EXC | 50.62% | 50.53% | 50.70% | 50.86% | 49.62% | 50.54% | 50.86% | 50.81% | 50.57% |
| Baltimore Gas and Electric Company | EXC | 48.11% | 45.64% | 45.57% | 46.33% | 47.15% | 44.66% | 44.64% | 45.23% | 45.92% |
| Commonwealth Edison Company | EXC | 44.39% | 44.71% | 45.00% | 44.94% | 45.28% | 44.64% | 45.04% | 45.15% | 44.89% |
| Delmarva Power & Light Company | EXC | 49.82% | 49.80% | 49.82% | 50.02% | 49.89% | 50.14% | 49.65% | 49.62% | 49.84% |
| PECO Energy Co. | EXC | 46.63% | 44.80% | 44.87% | 46.28% | 47.18% | 45.72% | 46.23% | 46.46% | 46.02% |
| Potomac Electric Power Company | EXC | 49.79% | 49.76% | 49.59% | 49.99% | 49.76% | 49.92% | 50.06% | 50.11% | 49.87% |
| Cleveland Electric Illuminating Company | FE | 44.26% | 44.51% | 44.46% | 44.56% | 43.50% | 43.69% | 44.52% | 44.73% | 44.28% |
| Jersey Central Power & Light Company | FE | 31.26% | 31.77% | 31.92% | 30.54% | 30.66% | 31.19% | 34.48% | 34.70% | 32.07% |
| Metropolitan Edison Company | FE | 50.28% | 51.54% | 52.22% | 46.79% | 45.75% | 46.90% | 47.82% | 47.67% | 48.62% |
| Monongahela Power Company | FE | 50.02% | 50.93% | 50.95% | 51.13% | 49.29% | 48.47% | 49.43% | 50.85% | 50.13% |
| Ohio Edison Company | FE | 30.84% | 28.58% | 29.18% | 30.07% | 30.86% | 32.67% | 33.11% | 35.09% | 31.30% |
| Pennsylvania Electric Company | FE | 48.22% | 49.07% | 46.15% | 46.11% | 45.99% | 46.10% | 46.91% | 47.94% | 47.06% |
| Pennsylvania Power Company | FE | 46.91% | 48.29% | 49.31% | 50.97% | 41.73% | 43.11% | 44.30% | 46.18% | 46.35% |
| Potomac Edison Company | FE | 46.31% | 47.01% | 46.71% | 47.65% | 47.08% | 47.35% | 47.36% | 48.41% | 47.23% |
| Toledo Edison Company | FE | 39.24% | 39.43% | 39.22% | 39.57% | 37.75% | 37.75% | 39.40% | 39.96% | 39.04% |
| West Penn Power Company | FE | 53.89% | 49.37% | 45.32% | 46.50% | 46.86% | 47.91% | 48.91% | 47.18% | 48.24% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| Madison Gas and Electric Company | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| Florida Power & Light Company | NEE | 40.22% | 38.70% | 35.97% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 37.97% |
| Gulf Power Company | NEE | 47.48% | 38.85% | 41.94% | NA | NA | NA | NA | NA | 42.76% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| Oklahoma Gas and Electric Company | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Power Company | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Arizona Public Service Company | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| Public Service Company of New Mexico | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Kentucky Utilities Company | PPL | 47.03% | 47.19% | 44.56% | 45.15% | 45.24% | 45.49% | 45.92% | 46.00% | 45.82% |
| Louisville Gas and Electric Company | PPL | 45.90% | 46.12% | 43.84% | 44.20% | 44.65% | 45.03% | 45.54% | 44.58% | 44.98% |
| PPL Electric Utilities Corporation | PPL | 45.56% | 45.49% | 45.48% | 45.48% | 45.35% | 45.72% | 44.96% | 45.43% | 45.43% |
| Oncor Electric Delivery Company LLC | SRE | 45.09% | 42.57% | 40.21% | 40.53% | 40.71% | 37.69% | 39.66% | 41.14% | 40.95% |
| San Diego Gas & Electric Company | SRE | 42.57% | 44.83% | 43.40% | 44.21% | 44.83% | 45.53% | 44.08% | 44.91% | 44.29% |
| Sharyland Utilities, LLC | SRE | NA | NA | 54.95% | 55.38% | 55.08% | 53.61% | 53.66% | 54.14% | 54.47% |
| Alabama Power Company | SO | 48.55% | 47.46% | 47.77% | 52.23% | 51.87% | 52.49% | 51.14% | 52.93% | 50.56% |
| Georgia Power Company | SO | 44.62% | 43.61% | 43.57% | 40.98% | 42.73% | 45.03% | 46.19% | 49.94% | 44.58% |
| Mississippi Power Company | SO | 49.77% | 50.13% | 50.27% | 49.65% | 54.72% | 56.13% | 57.00% | 60.66% | 53.54% |
| Gulf Power Company | SO | NA | NA | NA | 40.27% | 44.66% | 45.10% | 45.73% | 45.81% | 44.31% |
| Upper Michigan Energy Resources Corporation | WEC | 43.91% | 45.55% | 47.46% | 52.99% | 44.92% | 45.47% | 29.96% | 50.15% | 45.05% |
| Wisconsin Electric Power Company | WEC | 43.08% | 43.36% | 44.22% | 43.97% | 40.75% | 40.91% | 43.53% | 44.06% | 42.99% |
| Wisconsin Public Service Corporation | WEC | 45.63% | 40.96% | 41.12% | 42.67% | 39.41% | 40.47% | 41.65% | 41.94% | 41.73% |
| Northern States Power Company - MN | XEL | 48.21% | 46.34% | 46.36% | 47.19% | 47.36% | 47.39% | 47.41% | 47.62% | 47.23% |
| Northern States Power Company - WI | XEL | 46.44% | 46.51% | 46.41% | 46.40% | 51.55% | 46.15% | 46.21% | 46.64% | 47.04% |
| Public Service Company of Colorado | XEL | 43.65% | 42.47% | 43.32% | 43.69% | 43.92% | 45.83% | 43.33% | 43.50% | 43.71% |
| Southwestern Public Service Company | XEL | 45.79% | 45.86% | 45.87% | 45.83% | 43.71% | 46.12% | 46.46% | 46.45% | 45.76% |
| Mean | | 46.59% | 46.45% | 46.36% | 46.49% | 46.31% | 46.59% | 46.40% | 46.77% | 46.48% |

Frequency Distribution of Market Risk Premium, 1926 - 2019




| Year | Large Company Stocks Total Returns Jan-Dec* | Long-Term Government Bond Income Returns Jan-Dec* | MRP Jan-Dec* |
|---|---|---|---|
| 1926 | 0.1162 | 0.0373 | 0.0789 |
| 1927 | 0.3749 | 0.0341 | 0.3408 |
| 1928 | 0.4361 | 0.0322 | 0.4039 |
| 1929 | -0.0842 | 0.0347 | -0.1189 |
| 1930 | -0.2490 | 0.0332 | -0.2822 |
| 1931 | -0.4334 | 0.0333 | -0.4667 |
| 1932 | -0.0819 | 0.0369 | -0.1188 |
| 1933 | 0.5399 | 0.0312 | 0.5087 |
| 1934 | -0.0144 | 0.0318 | -0.0462 |
| 1935 | 0.4767 | 0.0281 | 0.4486 |
| 1936 | 0.3392 | 0.0277 | 0.3115 |
| 1937 | -0.3503 | 0.0266 | -0.3769 |
| 1938 | 0.3112 | 0.0264 | 0.2848 |
| 1939 | -0.0041 | 0.0240 | -0.0281 |
| 1940 | -0.0978 | 0.0223 | -0.1201 |
| 1941 | -0.1159 | 0.0194 | -0.1353 |
| 1942 | 0.2034 | 0.0246 | 0.1788 |
| 1943 | 0.2590 | 0.0244 | 0.2346 |
| 1944 | 0.1975 | 0.0246 | 0.1729 |
| 1945 | 0.3644 | 0.0234 | 0.3410 |
| 1946 | -0.0807 | 0.0204 | -0.1011 |
| 1947 | 0.0571 | 0.0213 | 0.0358 |
| 1948 | 0.0550 | 0.0240 | 0.0310 |
| 1949 | 0.1879 | 0.0225 | 0.1654 |
| 1950 | 0.3171 | 0.0212 | 0.2959 |
| 1951 | 0.2402 | 0.0238 | 0.2164 |
| 1952 | 0.1837 | 0.0266 | 0.1571 |
| 1953 | -0.0099 | 0.0284 | -0.0383 |
| 1954 | 0.5262 | 0.0279 | 0.4983 |
| 1955 | 0.3156 | 0.0275 | 0.2881 |
| 1956 | 0.0656 | 0.0299 | 0.0357 |
| 1957 | -0.1078 | 0.0344 | -0.1422 |
| 1958 | 0.4336 | 0.0327 | 0.4009 |
| 1959 | 0.1196 | 0.0401 | 0.0795 |
| 1960 | 0.0047 | 0.0426 | -0.0379 |
| 1961 | 0.2689 | 0.0383 | 0.2306 |
| 1962 | -0.0873 | 0.0400 | -0.1273 |
| 1963 | 0.2280 | 0.0389 | 0.1891 |
| 1964 | 0.1648 | 0.0415 | 0.1233 |
| 1965 | 0.1245 | 0.0419 | 0.0826 |
| 1966 | -0.1006 | 0.0449 | -0.1455 |
| 1967 | 0.2398 | 0.0459 | 0.1939 |
| 1968 | 0.1106 | 0.0550 | 0.0556 |
| 1969 | -0.0850 | 0.0595 | -0.1445 |
| 1970 | 0.0386 | 0.0674 | -0.0288 |
| 1971 | 0.1430 | 0.0632 | 0.0798 |
| 1972 | 0.1899 | 0.0587 | 0.1312 |
| 1973 | -0.1469 | 0.0651 | -0.2120 |
| 1974 | -0.2647 | 0.0727 | -0.3374 |
| 1975 | 0.3723 | 0.0799 | 0.2924 |
| 1976 | 0.2393 | 0.0789 | 0.1604 |
| 1977 | -0.0716 | 0.0714 | -0.1430 |
| 1978 | 0.0657 | 0.0790 | -0.0133 |
| 1979 | 0.1861 | 0.0886 | 0.0975 |
| 1980 | 0.3250 | 0.0997 | 0.2253 |
| 1981 | -0.0492 | 0.1155 | -0.1647 |
| 1982 | 0.2155 | 0.1350 | 0.0805 |
| 1983 | 0.2256 | 0.1038 | 0.1218 |
| 1984 | 0.0627 | 0.1174 | -0.0547 |
| 1985 | 0.3173 | 0.1125 | 0.2048 |
| 1986 | 0.1867 | 0.0898 | 0.0969 |
| 1987 | 0.0525 | 0.0792 | -0.0267 |
| 1988 | 0.1661 | 0.0897 | 0.0764 |
| 1989 | 0.3169 | 0.0881 | 0.2288 |
| 1990 | -0.0310 | 0.0819 | -0.1129 |
| 1991 | 0.3047 | 0.0822 | 0.2225 |
| 1992 | 0.0762 | 0.0726 | 0.0036 |
| 1993 | 0.1008 | 0.0717 | 0.0291 |
| 1994 | 0.0132 | 0.0659 | -0.0527 |
| 1995 | 0.3758 | 0.0760 | 0.2998 |
| 1996 | 0.2296 | 0.0618 | 0.1678 |
| 1997 | 0.3336 | 0.0664 | 0.2672 |
| 1998 | 0.2858 | 0.0583 | 0.2275 |
| 1999 | 0.2104 | 0.0557 | 0.1547 |
| 2000 | -0.0910 | 0.0650 | -0.1560 |
| 2001 | -0.1189 | 0.0553 | -0.1742 |
| 2002 | -0.2210 | 0.0559 | -0.2769 |
| 2003 | 0.2868 | 0.0480 | 0.2388 |
| 2004 | 0.1088 | 0.0502 | 0.0586 |
| 2005 | 0.0491 | 0.0469 | 0.0022 |
| 2006 | 0.1579 | 0.0468 | 0.1111 |
| 2007 | 0.0549 | 0.0486 | 0.0063 |
| 2008 | -0.3700 | 0.0445 | -0.4145 |
| 2009 | 0.2646 | 0.0347 | 0.2299 |
| 2010 | 0.1506 | 0.0425 | 0.1081 |
| 2011 | 0.0211 | 0.0382 | -0.0171 |
| 2012 | 0.1600 | 0.0246 | 0.1354 |
| 2013 | 0.3239 | 0.0288 | 0.2951 |
| 2014 | 0.1369 | 0.0341 | 0.1028 |
| 2015 | 0.0138 | 0.0247 | -0.0109 |
| 2016 | 0.1196 | 0.0230 | 0.0966 |
| 2017 | 0.2183 | 0.0267 | 0.1916 |
| 2018 | -0.0438 | 0.0282 | -0.0720 |
| 2019 | 0.3149 | 0.0255 | 0.2894 |
| Average | 0.1209 | 0.0494 | 0.0715 |
| Std. Dev. | 0.1976 | 0.0262 | 0.1987 |

Source: Duff & Phelps, 2020 SBBI Yearbook, Appendix A-1, A-7

**MRP**

| *Bin* | *Frequency* | *Cumulative %* |
|---|---|---|
| -50.00% | 0 | 0.0% |
| -47.50% | 0 | 0.0% |
| -45.00% | 1 | 1.1% |
| -42.50% | 0 | 1.1% |
| -40.00% | 1 | 2.1% |
| -37.50% | 1 | 3.2% |
| -35.00% | 0 | 3.2% |
| -32.50% | 1 | 4.3% |
| -30.00% | 0 | 4.3% |
| -27.50% | 2 | 6.4% |
| -25.00% | 0 | 6.4% |
| -22.50% | 0 | 6.4% |
| -20.00% | 1 | 7.4% |
| -17.50% | 0 | 7.4% |
| -15.00% | 3 | 10.6% |
| -12.50% | 6 | 17.0% |
| -10.00% | 5 | 22.3% |
| -7.50% | 0 | 22.3% |
| -5.00% | 3 | 25.5% |
| -2.50% | 6 | 31.9% |
| 0.00% | 3 | 35.1% |
| 2.50% | 3 | 38.3% |
| 5.00% | 4 | 42.6% |
| 7.50% | 2 | 44.7% |
| 10.00% | 9 | 54.3% |
| 12.50% | 5 | 59.6% |
| 15.00% | 2 | 61.7% |
| 17.50% | 6 | 68.1% |
| 20.00% | 4 | 72.3% |
| 22.50% | 3 | 75.5% |
| 25.00% | 7 | 83.0% |
| 27.50% | 1 | 84.0% |
| 30.00% | 7 | 91.5% |
| 32.50% | 1 | 92.6% |
| 35.00% | 2 | 94.7% |
| 37.50% | 0 | 94.7% |
| 40.00% | 0 | 94.7% |
| 42.50% | 2 | 96.8% |
| 45.00% | 1 | 97.9% |
| 47.50% | 0 | 97.9% |
| 50.00% | 1 | 98.9% |
| 51.00% | 1 | 100.0% |

Count: 94

| Highest MRP from Direct | Rank | |
|---|---|---|
| 12.19% | 57.90% | 42.10% |

Historical Market Return from Direct

| D'Ascendis | % Rank | Occurrence |
|---|---|---|
| 14.48% | 50.70% | 46 |
| 14.62% | 50.90% | 46 |
| | | 94 |

CAPM vs. ECAPM Security Market Line
Using Mr. Baudino's Inputs

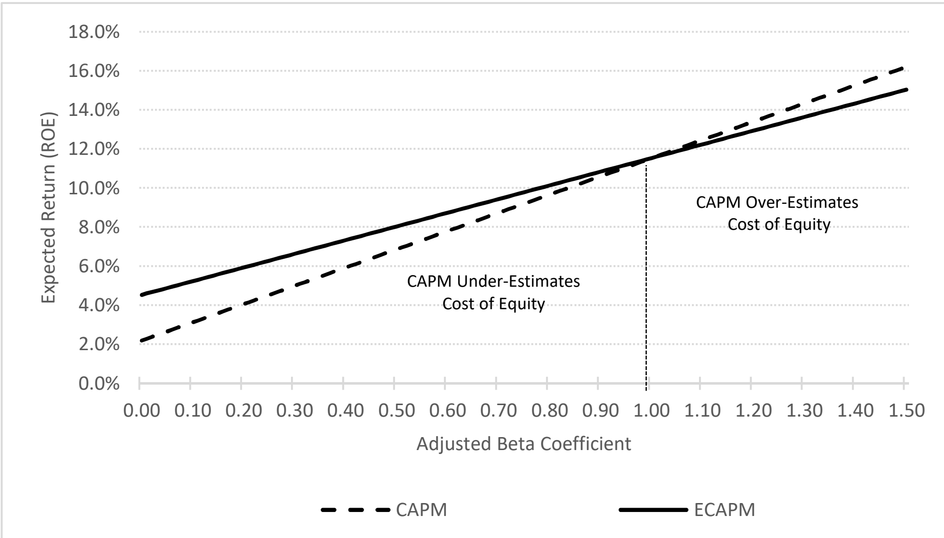
| | | | | | |
|---|---|---|---|---|---|
| Risk-Free Rate | 2.19% | | ECAPM | 0.25 |
| MRP | 9.34% | | Factors | 0.75 |

| | | | ECAPM alpha | |
|---|---|---|---|---|
| | CAPM | ECAPM | 1.00% | 2.00% |
| 0.00 | 2.19% | 4.53% | 3.19% | 4.19% |
| 0.01 | 2.28% | 4.60% | 3.27% | 4.26% |
| 0.02 | 2.38% | 4.67% | 3.36% | 4.34% |
| 0.03 | 2.47% | 4.74% | 3.44% | 4.41% |
| 0.04 | 2.56% | 4.81% | 3.52% | 4.48% |
| 0.05 | 2.66% | 4.88% | 3.61% | 4.56% |
| 0.06 | 2.75% | 4.95% | 3.69% | 4.63% |
| 0.07 | 2.84% | 5.02% | 3.77% | 4.70% |
| 0.08 | 2.94% | 5.09% | 3.86% | 4.78% |
| 0.09 | 3.03% | 5.16% | 3.94% | 4.85% |
| 0.10 | 3.12% | 5.23% | 4.02% | 4.92% |
| 0.11 | 3.22% | 5.30% | 4.11% | 5.00% |
| 0.12 | 3.31% | 5.37% | 4.19% | 5.07% |
| 0.13 | 3.40% | 5.44% | 4.27% | 5.14% |
| 0.14 | 3.50% | 5.51% | 4.36% | 5.22% |
| 0.15 | 3.59% | 5.58% | 4.44% | 5.29% |
| 0.16 | 3.68% | 5.65% | 4.52% | 5.36% |
| 0.17 | 3.78% | 5.72% | 4.61% | 5.44% |
| 0.18 | 3.87% | 5.79% | 4.69% | 5.51% |
| 0.19 | 3.96% | 5.86% | 4.77% | 5.58% |
| 0.20 | 4.06% | 5.93% | 4.86% | 5.66% |
| 0.21 | 4.15% | 6.00% | 4.94% | 5.73% |
| 0.22 | 4.24% | 6.07% | 5.02% | 5.80% |
| 0.23 | 4.34% | 6.14% | 5.11% | 5.88% |
| 0.24 | 4.43% | 6.21% | 5.19% | 5.95% |
| 0.25 | 4.53% | 6.28% | 5.28% | 6.03% |
| 0.26 | 4.62% | 6.35% | 5.36% | 6.10% |
| 0.27 | 4.71% | 6.42% | 5.44% | 6.17% |
| 0.28 | 4.81% | 6.49% | 5.53% | 6.25% |
| 0.29 | 4.90% | 6.56% | 5.61% | 6.32% |
| 0.30 | 4.99% | 6.63% | 5.69% | 6.39% |
| 0.31 | 5.09% | 6.70% | 5.78% | 6.47% |
| 0.32 | 5.18% | 6.77% | 5.86% | 6.54% |
| 0.33 | 5.27% | 6.84% | 5.94% | 6.61% |
| 0.34 | 5.37% | 6.91% | 6.03% | 6.69% |
| 0.35 | 5.46% | 6.98% | 6.11% | 6.76% |
| 0.36 | 5.55% | 7.05% | 6.19% | 6.83% |
| 0.37 | 5.65% | 7.12% | 6.28% | 6.91% |
| 0.38 | 5.74% | 7.19% | 6.36% | 6.98% |
| 0.39 | 5.83% | 7.26% | 6.44% | 7.05% |
| 0.40 | 5.93% | 7.33% | 6.53% | 7.13% |
| 0.41 | 6.02% | 7.40% | 6.61% | 7.20% |
| 0.42 | 6.11% | 7.47% | 6.69% | 7.27% |
| 0.43 | 6.21% | 7.54% | 6.78% | 7.35% |
| 0.44 | 6.30% | 7.61% | 6.86% | 7.42% |
| 0.45 | 6.39% | 7.68% | 6.94% | 7.49% |
| 0.46 | 6.49% | 7.75% | 7.03% | 7.57% |
| 0.47 | 6.58% | 7.82% | 7.11% | 7.64% |

| | CAPM | ECAPM | 1.00% | 2.00% |
|---|---|---|---|---|
| 0.48 | 6.67% | 7.89% | 7.19% | 7.71% |
| 0.49 | 6.77% | 7.96% | 7.28% | 7.79% |
| 0.50 | 6.86% | 8.03% | 7.36% | 7.86% |
| 0.51 | 6.95% | 8.10% | 7.44% | 7.93% |
| 0.52 | 7.05% | 8.17% | 7.53% | 8.01% |
| 0.53 | 7.14% | 8.24% | 7.61% | 8.08% |
| 0.54 | 7.23% | 8.31% | 7.69% | 8.15% |
| 0.55 | 7.33% | 8.38% | 7.78% | 8.23% |
| 0.56 | 7.42% | 8.45% | 7.86% | 8.30% |
| 0.57 | 7.51% | 8.52% | 7.94% | 8.37% |
| 0.58 | 7.61% | 8.59% | 8.03% | 8.45% |
| 0.59 | 7.70% | 8.66% | 8.11% | 8.52% |
| 0.60 | 7.79% | 8.73% | 8.19% | 8.59% |
| 0.61 | 7.89% | 8.80% | 8.28% | 8.67% |
| 0.62 | 7.98% | 8.87% | 8.36% | 8.74% |
| 0.63 | 8.07% | 8.94% | 8.44% | 8.81% |
| 0.64 | 8.17% | 9.01% | 8.53% | 8.89% |
| 0.65 | 8.26% | 9.08% | 8.61% | 8.96% |
| 0.66 | 8.35% | 9.15% | 8.69% | 9.03% |
| 0.67 | 8.45% | 9.22% | 8.78% | 9.11% |
| 0.68 | 8.54% | 9.29% | 8.86% | 9.18% |
| 0.69 | 8.63% | 9.36% | 8.94% | 9.25% |
| 0.70 | 8.73% | 9.43% | 9.03% | 9.33% |
| 0.71 | 8.82% | 9.50% | 9.11% | 9.40% |
| 0.72 | 8.91% | 9.57% | 9.19% | 9.47% |
| 0.73 | 9.01% | 9.64% | 9.28% | 9.55% |
| 0.74 | 9.10% | 9.71% | 9.36% | 9.62% |
| 0.75 | 9.20% | 9.78% | 9.45% | 9.70% |
| 0.76 | 9.29% | 9.85% | 9.53% | 9.77% |
| 0.77 | 9.38% | 9.92% | 9.61% | 9.84% |
| 0.78 | 9.48% | 9.99% | 9.70% | 9.92% |
| 0.79 | 9.57% | 10.06% | 9.78% | 9.99% |
| 0.80 | 9.66% | 10.13% | 9.86% | 10.06% |
| 0.81 | 9.76% | 10.20% | 9.95% | 10.14% |
| 0.82 | 9.85% | 10.27% | 10.03% | 10.21% |
| 0.83 | 9.94% | 10.34% | 10.11% | 10.28% |
| 0.84 | 10.04% | 10.41% | 10.20% | 10.36% |
| 0.85 | 10.13% | 10.48% | 10.28% | 10.43% |
| 0.86 | 10.22% | 10.55% | 10.36% | 10.50% |
| 0.87 | 10.32% | 10.62% | 10.45% | 10.58% |
| 0.88 | 10.41% | 10.69% | 10.53% | 10.65% |
| 0.89 | 10.50% | 10.76% | 10.61% | 10.72% |
| 0.90 | 10.60% | 10.83% | 10.70% | 10.80% |
| 0.91 | 10.69% | 10.90% | 10.78% | 10.87% |
| 0.92 | 10.78% | 10.97% | 10.86% | 10.94% |
| 0.93 | 10.88% | 11.04% | 10.95% | 11.02% |
| 0.94 | 10.97% | 11.11% | 11.03% | 11.09% |
| 0.95 | 11.06% | 11.18% | 11.11% | 11.16% |
| 0.96 | 11.16% | 11.25% | 11.20% | 11.24% |
| 0.97 | 11.25% | 11.32% | 11.28% | 11.31% |
| 0.98 | 11.34% | 11.39% | 11.36% | 11.38% |
| 0.99 | 11.44% | 11.46% | 11.45% | 11.46% |
| 1.00 | 11.53% | 11.53% | 11.53% | 11.53% |
| 1.01 | 11.62% | 11.60% | 11.61% | 11.60% |

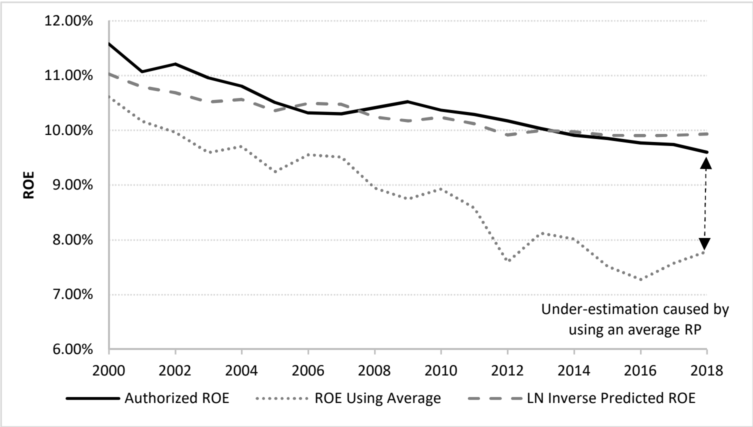
| | CAPM | ECAPM | 1.00% | 2.00% |
|---|---|---|---|---|
| 1.02 | 11.72% | 11.67% | 11.70% | 11.68% |
| 1.03 | 11.81% | 11.74% | 11.78% | 11.75% |
| 1.04 | 11.90% | 11.81% | 11.86% | 11.82% |
| 1.05 | 12.00% | 11.88% | 11.95% | 11.90% |
| 1.06 | 12.09% | 11.95% | 12.03% | 11.97% |
| 1.07 | 12.18% | 12.02% | 12.11% | 12.04% |
| 1.08 | 12.28% | 12.09% | 12.20% | 12.12% |
| 1.09 | 12.37% | 12.16% | 12.28% | 12.19% |
| 1.10 | 12.46% | 12.23% | 12.36% | 12.26% |
| 1.11 | 12.56% | 12.30% | 12.45% | 12.34% |
| 1.12 | 12.65% | 12.37% | 12.53% | 12.41% |
| 1.13 | 12.74% | 12.44% | 12.61% | 12.48% |
| 1.14 | 12.84% | 12.51% | 12.70% | 12.56% |
| 1.15 | 12.93% | 12.58% | 12.78% | 12.63% |
| 1.16 | 13.02% | 12.65% | 12.86% | 12.70% |
| 1.17 | 13.12% | 12.72% | 12.95% | 12.78% |
| 1.18 | 13.21% | 12.79% | 13.03% | 12.85% |
| 1.19 | 13.30% | 12.86% | 13.11% | 12.92% |
| 1.20 | 13.40% | 12.93% | 13.20% | 13.00% |
| 1.21 | 13.49% | 13.00% | 13.28% | 13.07% |
| 1.22 | 13.58% | 13.07% | 13.36% | 13.14% |
| 1.23 | 13.68% | 13.14% | 13.45% | 13.22% |
| 1.24 | 13.77% | 13.21% | 13.53% | 13.29% |
| 1.25 | 13.87% | 13.28% | 13.62% | 13.37% |
| 1.26 | 13.96% | 13.35% | 13.70% | 13.44% |
| 1.27 | 14.05% | 13.42% | 13.78% | 13.51% |
| 1.28 | 14.15% | 13.49% | 13.87% | 13.59% |
| 1.29 | 14.24% | 13.56% | 13.95% | 13.66% |
| 1.30 | 14.33% | 13.63% | 14.03% | 13.73% |
| 1.31 | 14.43% | 13.70% | 14.12% | 13.81% |
| 1.32 | 14.52% | 13.77% | 14.20% | 13.88% |
| 1.33 | 14.61% | 13.84% | 14.28% | 13.95% |
| 1.34 | 14.71% | 13.91% | 14.37% | 14.03% |
| 1.35 | 14.80% | 13.98% | 14.45% | 14.10% |
| 1.36 | 14.89% | 14.05% | 14.53% | 14.17% |
| 1.37 | 14.99% | 14.12% | 14.62% | 14.25% |
| 1.38 | 15.08% | 14.19% | 14.70% | 14.32% |
| 1.39 | 15.17% | 14.26% | 14.78% | 14.39% |
| 1.40 | 15.27% | 14.33% | 14.87% | 14.47% |
| 1.41 | 15.36% | 14.40% | 14.95% | 14.54% |
| 1.42 | 15.45% | 14.47% | 15.03% | 14.61% |
| 1.43 | 15.55% | 14.54% | 15.12% | 14.69% |
| 1.44 | 15.64% | 14.61% | 15.20% | 14.76% |
| 1.45 | 15.73% | 14.68% | 15.28% | 14.83% |
| 1.46 | 15.83% | 14.75% | 15.37% | 14.91% |
| 1.47 | 15.92% | 14.82% | 15.45% | 14.98% |
| 1.48 | 16.01% | 14.89% | 15.53% | 15.05% |
| 1.49 | 16.11% | 14.96% | 15.62% | 15.13% |
| 1.50 | 16.20% | 15.03% | 15.70% | 15.20% |

Source: Exhibit RAB-4


18.0%
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
Expected Return (ROE)
0.00 0.10 0.20 0.30 0.40 0.50 0.60 0.70 0.80 0.90 1.00 1.10 1.20 1.30 1.40 1.50
Adjusted Beta Coefficient
CAPM Over-Estimates
Cost of Equity
CAPM Under-Estimates
Cost of Equity
CAPM
ECAPM

Relative Accuracy of Average Equity Risk Premiums and Predicted Risk Premiums

| Rate Case Year | Auth. ROE [1] | Avg 30-Yr Treasury [2] | Average RP [3] | ROE Using Average | Error | LN Inverse Predicted RP [4] | LN Inverse Predicted ROE | Error |
|---|---|---|---|---|---|---|---|---|
| 2000 | 11.58% | 5.93% | 4.68% | 10.61% | -0.97% | 5.09% | 11.03% | -0.55% |
| 2001 | 11.07% | 5.49% | 4.68% | 10.17% | -0.90% | 5.30% | 10.79% | -0.28% |
| 2002 | 11.21% | 5.28% | 4.68% | 9.96% | -1.25% | 5.40% | 10.69% | -0.52% |
| 2003 | 10.96% | 4.92% | 4.68% | 9.60% | -1.36% | 5.59% | 10.51% | -0.45% |
| 2004 | 10.81% | 5.03% | 4.68% | 9.70% | -1.11% | 5.54% | 10.56% | -0.25% |
| 2005 | 10.51% | 4.57% | 4.68% | 9.24% | -1.27% | 5.79% | 10.36% | -0.15% |
| 2006 | 10.32% | 4.88% | 4.68% | 9.55% | -0.77% | 5.62% | 10.49% | 0.17% |
| 2007 | 10.30% | 4.84% | 4.68% | 9.51% | -0.79% | 5.64% | 10.48% | 0.18% |
| 2008 | 10.41% | 4.27% | 4.68% | 8.94% | -1.47% | 5.98% | 10.24% | -0.17% |
| 2009 | 10.52% | 4.07% | 4.68% | 8.75% | -1.77% | 6.10% | 10.17% | -0.35% |
| 2010 | 10.37% | 4.25% | 4.68% | 8.92% | -1.45% | 5.99% | 10.24% | -0.13% |
| 2011 | 10.29% | 3.90% | 4.68% | 8.58% | -1.71% | 6.21% | 10.12% | -0.17% |
| 2012 | 10.17% | 2.92% | 4.68% | 7.59% | -2.58% | 6.99% | 9.91% | -0.26% |
| 2013 | 10.03% | 3.45% | 4.68% | 8.12% | -1.91% | 6.55% | 9.99% | -0.04% |
| 2014 | 9.91% | 3.34% | 4.68% | 8.01% | -1.90% | 6.63% | 9.97% | 0.06% |
| 2015 | 9.85% | 2.84% | 4.68% | 7.52% | -2.33% | 7.06% | 9.91% | 0.06% |
| 2016 | 9.77% | 2.60% | 4.68% | 7.27% | -2.50% | 7.30% | 9.90% | 0.13% |
| 2017 | 9.74% | 2.89% | 4.68% | 7.57% | -2.17% | 7.02% | 9.91% | 0.17% |
| 2018 | 9.60% | 3.11% | 4.68% | 7.79% | -1.81% | 6.82% | 9.93% | 0.33% |
| 2019 | 9.65% | 2.58% | 4.68% | 7.25% | -2.40% | 7.32% | 9.90% | 0.25% |
| Average: | 10.35% | 4.06% | 4.68% | 8.73% | -1.62% | 6.20% | 10.26% | -0.10% |
| | | | | | | | Stdev: | 0.26% |




Notes

[1] Source: Regulatory Research Associates: Regulatory Focus, Major Rate Case Decisions January - December 2019, January 31, 2020; all electric rate cases
[2] Source: Bloomberg Professional
[3] Source: Exhibit DWD-5
[4] Source: Exhibit DWD-5 (regression coefficients)

Retention Ratio Regression Analysis - Mr. O'Donnell's Proxy Group

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.33588834 |
| R Square | 0.112820977 |
| Adjusted R Square | 0.110614064 |
| Standard Error | 0.187578324 |
| Observations | 404 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1.798746443 | 1.798746443 | 51.12162426 | 4.12617E-12 |
| Residual | 402 | 14.14462237 | 0.035185628 | | |
| Total | 403 | 15.94336882 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.108 | 0.012 | 9.201 | 0.000 | 0.085 | 0.131 |
| Retention Ratio | -0.166 | 0.023 | -7.150 | 0.000 | -0.211 | -0.120 |

Source: Value Line

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2004 | ALE | 22.22% | 77.78% | 13.03% |
| 2005 | ALE | 50.40% | 49.60% | -0.53% |
| 2006 | ALE | 52.35% | 47.65% | 1.33% |
| 2007 | ALE | 53.25% | 46.75% | -1.44% |
| 2008 | ALE | 60.99% | 39.01% | 0.64% |
| 2009 | ALE | 93.12% | 6.88% | 9.29% |
| 2010 | ALE | 80.37% | 19.63% | 9.42% |
| 2011 | ALE | 67.17% | 32.83% | 3.80% |
| 2012 | ALE | 71.32% | 28.68% | 4.27% |
| 2013 | ALE | 72.24% | 27.76% | 5.48% |
| 1996 | LNT | 86.78% | 13.22% | 6.92% |
| 1997 | LNT | 105.26% | -5.26% | -0.07% |
| 1998 | LNT | 158.73% | -58.73% | 13.28% |
| 1999 | LNT | 91.32% | 8.68% | 2.08% |
| 2000 | LNT | 80.97% | 19.03% | 3.42% |
| 2001 | LNT | 82.64% | 17.36% | 2.46% |
| 2002 | LNT | 169.49% | -69.49% | 18.83% |
| 2003 | LNT | 63.69% | 36.31% | 11.10% |
| 2004 | LNT | 55.14% | 44.86% | 2.50% |
| 2005 | LNT | 47.51% | 52.49% | 7.55% |
| 2006 | LNT | 55.83% | 44.17% | 8.91% |
| 2007 | LNT | 47.21% | 52.79% | 4.97% |
| 2008 | LNT | 55.12% | 44.88% | 7.73% |
| 2009 | LNT | 78.95% | 21.05% | 13.86% |
| 2010 | LNT | 57.45% | 42.55% | 4.34% |
| 2011 | LNT | 61.82% | 38.18% | 3.86% |
| 2012 | LNT | 59.02% | 40.98% | 5.80% |
| 2013 | LNT | 56.97% | 43.03% | 6.17% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1996 | AEE | 87.76% | 12.24% | 4.29% |
| 1997 | AEE | 104.10% | -4.10% | 2.83% |
| 1998 | AEE | 90.07% | 9.93% | 3.32% |
| 1999 | AEE | 90.39% | 9.61% | 1.35% |
| 2000 | AEE | 76.28% | 23.72% | -0.15% |
| 2001 | AEE | 74.49% | 25.51% | -3.63% |
| 2002 | AEE | 95.49% | 4.51% | 3.17% |
| 2003 | AEE | 80.89% | 19.11% | -1.11% |
| 2004 | AEE | 90.07% | 9.93% | 0.24% |
| 2005 | AEE | 81.15% | 18.85% | -2.03% |
| 2006 | AEE | 95.49% | 4.51% | -1.20% |
| 2007 | AEE | 85.23% | 14.77% | -4.09% |
| 2008 | AEE | 88.19% | 11.81% | -5.99% |
| 2009 | AEE | 55.40% | 44.60% | -2.44% |
| 2010 | AEE | 55.60% | 44.40% | -2.53% |
| 2011 | AEE | 63.16% | 36.84% | 2.15% |
| 2012 | AEE | 66.39% | 33.61% | 3.31% |
| 2013 | AEE | 76.19% | 23.81% | 9.85% |
| 1996 | AEP | 76.43% | 23.57% | 27.79% |
| 1997 | AEP | 73.17% | 26.83% | 24.39% |
| 1998 | AEP | 85.41% | 14.59% | 24.95% |
| 1999 | AEP | 89.22% | 10.78% | 26.43% |
| 2000 | AEP | 230.77% | -130.77% | 38.93% |
| 2001 | AEP | 73.39% | 26.61% | -2.29% |
| 2002 | AEP | 83.92% | 16.08% | 0.22% |
| 2003 | AEP | 65.22% | 34.78% | 3.44% |
| 2004 | AEP | 53.64% | 46.36% | 2.67% |
| 2005 | AEP | 53.79% | 46.21% | -0.05% |
| 2006 | AEP | 52.45% | 47.55% | 2.36% |
| 2007 | AEP | 55.24% | 44.76% | 1.40% |
| 2008 | AEP | 54.85% | 45.15% | 1.84% |
| 2009 | AEP | 55.22% | 44.78% | 2.98% |
| 2010 | AEP | 65.77% | 34.23% | 6.96% |
| 2011 | AEP | 59.11% | 40.89% | 6.45% |
| 2012 | AEP | 63.09% | 36.91% | 4.53% |
| 2013 | AEP | 61.32% | 38.68% | 4.73% |
| 1996 | CMS | 41.63% | 58.37% | -8.29% |
| 1997 | CMS | 43.68% | 56.32% | -76.68% |
| 1998 | CMS | 56.25% | 43.75% | -91.91% |
| 1999 | CMS | 48.77% | 51.23% | -168.39% |
| 2000 | CMS | 57.71% | 42.29% | -156.41% |
| 2001 | CMS | 114.96% | -14.96% | -154.82% |
| 2007 | CMS | 31.25% | 68.75% | 25.07% |
| 2008 | CMS | 29.27% | 70.73% | 8.33% |
| 2009 | CMS | 53.76% | 46.24% | 14.17% |
| 2010 | CMS | 49.62% | 50.38% | 7.30% |
| 2011 | CMS | 57.93% | 42.07% | 6.44% |
| 2012 | CMS | 62.75% | 37.25% | 7.26% |
| 2013 | CMS | 61.45% | 38.55% | 6.94% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1997 | ED | 71.19% | 28.81% | 1.64% |
| 1998 | ED | 69.74% | 30.26% | -0.88% |
| 1999 | ED | 68.37% | 31.63% | -5.08% |
| 2000 | ED | 79.56% | 20.44% | 3.19% |
| 2001 | ED | 68.54% | 31.46% | -0.51% |
| 2002 | ED | 70.93% | 29.07% | 3.58% |
| 2003 | ED | 79.15% | 20.85% | 4.81% |
| 2004 | ED | 97.41% | 2.59% | 7.10% |
| 2005 | ED | 76.25% | 23.75% | 3.43% |
| 2006 | ED | 77.97% | 22.03% | 4.27% |
| 2007 | ED | 66.67% | 33.33% | 2.30% |
| 2008 | ED | 69.64% | 30.36% | 3.36% |
| 2009 | ED | 75.16% | 24.84% | 3.09% |
| 2010 | ED | 68.59% | 31.41% | 3.36% |
| 2011 | ED | 67.23% | 32.77% | 2.24% |
| 2012 | ED | 62.69% | 37.31% | 1.43% |
| 2013 | ED | 62.60% | 37.40% | 3.26% |
| 1997 | D | 86.00% | 14.00% | 19.21% |
| 1998 | D | 150.00% | -50.00% | 24.00% |
| 1999 | D | 86.00% | 14.00% | 10.86% |
| 2000 | D | 103.20% | -3.20% | 8.27% |
| 2001 | D | 86.58% | 13.42% | 16.43% |
| 2002 | D | 53.53% | 46.47% | 1.83% |
| 2003 | D | 65.82% | 34.18% | 14.11% |
| 2004 | D | 61.03% | 38.97% | 9.75% |
| 2005 | D | 89.33% | 10.67% | 17.56% |
| 2006 | D | 57.50% | 42.50% | 4.66% |
| 2007 | D | 68.54% | 31.46% | 6.83% |
| 2008 | D | 51.97% | 48.03% | 0.76% |
| 2009 | D | 66.29% | 33.71% | 3.14% |
| 2010 | D | 63.32% | 36.68% | 2.23% |
| 2011 | D | 71.38% | 28.62% | 4.62% |
| 2012 | D | 76.73% | 23.27% | 5.22% |
| 2013 | D | 72.82% | 27.18% | 1.16% |
| 2007 | DUK | 71.67% | 28.33% | 1.45% |
| 2008 | DUK | 89.11% | 10.89% | 6.07% |
| 2009 | DUK | 83.19% | 16.81% | 4.45% |
| 2010 | DUK | 72.39% | 27.61% | 0.58% |
| 2011 | DUK | 71.74% | 28.26% | -1.92% |
| 2012 | DUK | 81.67% | 18.33% | 2.91% |
| 2013 | DUK | 77.64% | 22.36% | 1.03% |
| 2004 | EIX | 115.94% | -15.94% | 76.47% |
| 2005 | EIX | 30.54% | 69.46% | 0.34% |
| 2006 | EIX | 33.54% | 66.46% | -0.02% |
| 2007 | EIX | 35.54% | 64.46% | 7.91% |
| 2008 | EIX | 33.42% | 66.58% | 2.36% |
| 2009 | EIX | 38.58% | 61.42% | 7.66% |
| 2010 | EIX | 37.91% | 62.09% | 6.15% |
| 2011 | EIX | 39.94% | 60.06% | 5.86% |
| 2012 | EIX | 28.79% | 71.21% | 0.58% |
| 2013 | EIX | 36.24% | 63.76% | -21.63% |
| 1997 | ETR | 80.00% | 20.00% | 11.04% |
| 1998 | ETR | 67.57% | 32.43% | 11.36% |
| 1999 | ETR | 53.33% | 46.67% | 12.39% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2000 | ETR | 41.08% | 58.92% | 8.38% |
| 2001 | ETR | 41.56% | 58.44% | 12.01% |
| 2002 | ETR | 36.41% | 63.59% | 9.01% |
| 2003 | ETR | 43.36% | 56.64% | 11.09% |
| 2004 | ETR | 48.09% | 51.91% | 10.12% |
| 2005 | ETR | 49.09% | 50.91% | 8.87% |
| 2006 | ETR | 40.30% | 59.70% | 7.18% |
| 2007 | ETR | 46.07% | 53.93% | 2.23% |
| 2008 | ETR | 48.39% | 51.61% | -3.44% |
| 2009 | ETR | 47.62% | 52.38% | -0.49% |
| 2010 | ETR | 48.65% | 51.35% | -1.50% |
| 2011 | ETR | 43.97% | 56.03% | -0.49% |
| 2012 | ETR | 55.15% | 44.85% | -1.35% |
| 2013 | ETR | 66.94% | 33.06% | 4.83% |
| 2001 | ES | 32.85% | 67.15% | -8.32% |
| 2002 | ES | 49.07% | 50.93% | 14.69% |
| 2003 | ES | 46.77% | 53.23% | 15.13% |
| 2004 | ES | 69.23% | 30.77% | 20.99% |
| 2005 | ES | 69.39% | 30.61% | 21.44% |
| 2006 | ES | 89.02% | 10.98% | 25.85% |
| 2007 | ES | 49.06% | 50.94% | 4.09% |
| 2008 | ES | 44.62% | 55.38% | 7.05% |
| 2009 | ES | 49.74% | 50.26% | 7.23% |
| 2010 | ES | 49.05% | 50.95% | 6.64% |
| 2011 | ES | 49.55% | 50.45% | 6.94% |
| 2012 | ES | 69.84% | 30.16% | 10.93% |
| 2013 | ES | 59.04% | 40.96% | 5.48% |
| 1996 | HE | 93.08% | 6.92% | 4.99% |
| 1997 | HE | 88.41% | 11.59% | 4.01% |
| 1998 | HE | 83.78% | 16.22% | 2.06% |
| 1999 | HE | 85.52% | 14.48% | -0.31% |
| 2000 | HE | 97.64% | 2.36% | 3.64% |
| 2001 | HE | 77.50% | 22.50% | -3.34% |
| 2002 | HE | 76.54% | 23.46% | -6.90% |
| 2003 | HE | 78.48% | 21.52% | -7.12% |
| 2004 | HE | 91.18% | 8.82% | -7.33% |
| 2005 | HE | 84.93% | 15.07% | -2.21% |
| 2006 | HE | 93.23% | 6.77% | 3.38% |
| 2007 | HE | 111.71% | -11.71% | 9.88% |
| 2008 | HE | 115.89% | -15.89% | 10.00% |
| 2009 | HE | 136.26% | -36.26% | 13.24% |
| 2010 | HE | 102.48% | -2.48% | 4.94% |
| 2011 | HE | 86.11% | 13.89% | 11.67% |
| 2012 | HE | 74.25% | 25.75% | 2.80% |
| 2013 | HE | 76.54% | 23.46% | 5.96% |
| 1996 | IDA | 84.16% | 15.84% | 9.88% |
| 1997 | IDA | 80.17% | 19.83% | -1.38% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1998 | IDA | 78.48% | 21.52% | -10.03% |
| 1999 | IDA | 76.54% | 23.46% | 9.04% |
| 2000 | IDA | 53.14% | 46.86% | -1.34% |
| 2001 | IDA | 55.52% | 44.48% | 6.37% |
| 2002 | IDA | 114.11% | -14.11% | 12.47% |
| 2003 | IDA | 177.08% | -77.08% | 24.13% |
| 2004 | IDA | 63.16% | 36.84% | 8.77% |
| 2005 | IDA | 68.57% | 31.43% | 12.70% |
| 2006 | IDA | 51.06% | 48.94% | 8.62% |
| 2007 | IDA | 64.52% | 35.48% | 12.85% |
| 2008 | IDA | 55.05% | 44.95% | 11.01% |
| 2009 | IDA | 45.45% | 54.55% | 7.94% |
| 2010 | IDA | 40.68% | 59.32% | 5.70% |
| 2011 | IDA | 35.71% | 64.29% | 3.28% |
| 2012 | IDA | 40.65% | 59.35% | 4.59% |
| 2013 | IDA | 43.13% | 56.87% | 4.32% |
| 1998 | MGEE | 93.48% | 6.52% | 4.51% |
| 1999 | MGEE | 87.88% | 12.12% | 3.69% |
| 2000 | MGEE | 79.28% | 20.72% | -0.94% |
| 2001 | MGEE | 82.41% | 17.59% | 5.70% |
| 2002 | MGEE | 78.76% | 21.24% | 6.81% |
| 2003 | MGEE | 78.95% | 21.05% | 7.70% |
| 2004 | MGEE | 77.12% | 22.88% | 5.49% |
| 2005 | MGEE | 87.62% | 12.38% | 10.41% |
| 2006 | MGEE | 67.88% | 32.12% | 5.39% |
| 2007 | MGEE | 62.25% | 37.75% | 4.49% |
| 2008 | MGEE | 60.38% | 39.62% | 6.65% |
| 2009 | MGEE | 65.99% | 34.01% | 9.64% |
| 2010 | MGEE | 59.28% | 40.72% | 4.68% |
| 2011 | MGEE | 57.39% | 42.61% | 4.77% |
| 2012 | MGEE | 55.91% | 44.09% | 3.81% |
| 2013 | MGEE | 49.54% | 50.46% | 2.68% |
| 1996 | NEE | 55.26% | 44.74% | 6.82% |
| 1997 | NEE | 53.63% | 46.37% | 2.72% |
| 1998 | NEE | 51.81% | 48.19% | 5.53% |
| 1999 | NEE | 50.98% | 49.02% | 4.48% |
| 2000 | NEE | 52.17% | 47.83% | 3.04% |
| 2001 | NEE | 48.48% | 51.52% | 8.57% |
| 2002 | NEE | 57.71% | 42.29% | 11.41% |
| 2003 | NEE | 48.98% | 51.02% | 11.93% |
| 2004 | NEE | 52.85% | 47.15% | 11.36% |
| 2005 | NEE | 61.21% | 38.79% | 16.37% |
| 2006 | NEE | 46.44% | 53.56% | 8.87% |
| 2007 | NEE | 50.15% | 49.85% | 7.54% |
| 2008 | NEE | 43.73% | 56.27% | 3.83% |
| 2009 | NEE | 47.61% | 52.39% | 7.51% |
| 2010 | NEE | 42.19% | 57.81% | 5.27% |
| 2011 | NEE | 45.64% | 54.36% | 4.01% |
| 2012 | NEE | 52.63% | 47.37% | 7.58% |
| 2013 | NEE | 54.66% | 45.34% | 6.92% |
| 2005 | NWE | 58.48% | 41.52% | 5.90% |
| 2006 | NWE | 94.66% | 5.34% | 14.23% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2007 | NWE | 88.89% | 11.11% | 10.11% |
| 2008 | NWE | 74.58% | 25.42% | 7.29% |
| 2009 | NWE | 66.34% | 33.66% | 8.78% |
| 2010 | NWE | 63.55% | 36.45% | 6.99% |
| 2011 | NWE | 56.92% | 43.08% | 6.72% |
| 2012 | NWE | 65.49% | 34.51% | 8.56% |
| 2013 | NWE | 61.79% | 38.21% | 7.15% |
| 1998 | OGE | 65.69% | 34.31% | -1.39% |
| 1999 | OGE | 69.07% | 30.93% | 0.05% |
| 2000 | OGE | 70.53% | 29.47% | 1.14% |
| 2001 | OGE | 103.08% | -3.08% | 14.19% |
| 2002 | OGE | 93.06% | 6.94% | 13.50% |
| 2003 | OGE | 77.01% | 22.99% | 8.28% |
| 2004 | OGE | 75.28% | 24.72% | 9.10% |
| 2005 | OGE | 72.83% | 27.17% | 10.98% |
| 2006 | OGE | 54.47% | 45.53% | 7.31% |
| 2007 | OGE | 51.52% | 48.48% | 6.54% |
| 2008 | OGE | 56.00% | 44.00% | 9.27% |
| 2009 | OGE | 53.38% | 46.62% | 8.41% |
| 2010 | OGE | 48.67% | 51.33% | 2.92% |
| 2011 | OGE | 43.93% | 56.07% | -0.15% |
| 2012 | OGE | 44.69% | 55.31% | 1.88% |
| 2013 | OGE | 43.81% | 56.19% | 2.29% |
| 1996 | OTTR | 72.58% | 27.42% | 6.36% |
| 1997 | OTTR | 72.09% | 27.91% | 6.86% |
| 1998 | OTTR | 74.42% | 25.58% | 3.73% |
| 1999 | OTTR | 68.28% | 31.72% | 1.12% |
| 2000 | OTTR | 63.75% | 36.25% | 2.78% |
| 2001 | OTTR | 61.90% | 38.10% | 0.77% |
| 2002 | OTTR | 59.22% | 40.78% | 0.53% |
| 2003 | OTTR | 71.52% | 28.48% | -4.10% |
| 2004 | OTTR | 73.33% | 26.67% | -10.94% |
| 2005 | OTTR | 62.92% | 37.08% | -23.97% |
| 2006 | OTTR | 68.05% | 31.95% | -19.27% |
| 2007 | OTTR | 65.73% | 34.27% | 6.33% |
| 2008 | OTTR | 109.17% | -9.17% | 20.18% |
| 2009 | OTTR | 167.61% | -67.61% | 29.78% |
| 2010 | OTTR | 313.16% | -213.16% | 39.20% |
| 2011 | OTTR | 264.44% | -164.44% | 36.03% |
| 2012 | OTTR | 113.33% | -13.33% | 12.61% |
| 2013 | OTTR | 86.86% | 13.14% | 8.67% |
| 1996 | PNW | 41.70% | 58.30% | 8.36% |
| 1997 | PNW | 40.94% | 59.06% | -0.24% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1998 | PNW | 43.16% | 56.84% | -0.97% |
| 1999 | PNW | 41.82% | 58.18% | -2.81% |
| 2000 | PNW | 42.69% | 57.31% | -6.52% |
| 2001 | PNW | 41.58% | 58.42% | -0.18% |
| 2002 | PNW | 64.43% | 35.57% | 4.74% |
| 2003 | PNW | 68.65% | 31.35% | -0.86% |
| 2004 | PNW | 70.93% | 29.07% | -0.01% |
| 2005 | PNW | 86.16% | 13.84% | 9.88% |
| 2006 | PNW | 64.04% | 35.96% | 0.99% |
| 2007 | PNW | 70.95% | 29.05% | 5.73% |
| 2008 | PNW | 99.06% | 0.94% | 12.32% |
| 2009 | PNW | 92.92% | 7.08% | 10.56% |
| 2010 | PNW | 68.18% | 31.82% | 5.20% |
| 2011 | PNW | 70.23% | 29.77% | 5.94% |
| 2012 | PNW | 76.29% | 23.71% | 4.96% |
| 2013 | PNW | 60.93% | 39.07% | 4.54% |
| 1996 | PNM | 20.87% | 79.13% | 20.65% |
| 1997 | PNM | 33.60% | 66.40% | 7.11% |
| 1998 | PNM | 34.00% | 66.00% | 4.60% |
| 1999 | PNM | 41.09% | 58.91% | 12.27% |
| 2000 | PNM | 34.19% | 65.81% | 10.06% |
| 2001 | PNM | 20.31% | 79.69% | -1.57% |
| 2002 | PNM | 53.27% | 46.73% | -0.93% |
| 2003 | PNM | 53.04% | 46.96% | -19.53% |
| 2004 | PNM | 44.06% | 55.94% | 61.06% |
| 2005 | PNM | 50.64% | 49.36% | 69.24% |
| 2006 | PNM | 50.00% | 50.00% | 72.01% |
| 2007 | PNM | 119.74% | -19.74% | 87.44% |
| 2008 | PNM | 554.55% | -454.55% | 106.07% |
| 2009 | PNM | 86.21% | 13.79% | 21.18% |
| 2010 | PNM | 57.47% | 42.53% | 13.80% |
| 2011 | PNM | 46.30% | 53.70% | 9.10% |
| 2012 | PNM | 44.27% | 55.73% | 8.11% |
| 2013 | PNM | 48.23% | 51.77% | 3.87% |
| 2006 | POR | 59.65% | 40.35% | 20.49% |
| 2007 | POR | 39.91% | 60.09% | -1.20% |
| 2008 | POR | 69.78% | 30.22% | 5.80% |
| 2009 | POR | 77.10% | 22.90% | 11.58% |
| 2010 | POR | 62.65% | 37.35% | 4.95% |
| 2011 | POR | 54.36% | 45.64% | 2.63% |
| 2012 | POR | 57.75% | 42.25% | 4.66% |
| 2013 | POR | 62.15% | 37.85% | 6.43% |
| 1997 | PEG | 89.26% | 10.74% | 9.36% |
| 1998 | PEG | 77.14% | 22.86% | 6.22% |
| 1999 | PEG | 69.23% | 30.77% | 0.10% |
| 2000 | PEG | 60.67% | 39.33% | 0.83% |
| 2001 | PEG | 58.38% | 41.62% | 0.72% |
| 2002 | PEG | 57.45% | 42.55% | 8.39% |
| 2003 | PEG | 57.45% | 42.55% | 10.79% |
| 2004 | PEG | 72.37% | 27.63% | 15.86% |
| 2005 | PEG | 62.57% | 37.43% | 12.24% |
| 2006 | PEG | 61.62% | 38.38% | 11.83% |
| 2007 | PEG | 45.17% | 54.83% | -0.48% |
| 2008 | PEG | 44.48% | 55.52% | -2.79% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2009 | PEG | 43.18% | 56.82% | 0.38% |
| 2010 | PEG | 44.63% | 55.37% | 2.52% |
| 2011 | PEG | 44.05% | 55.95% | -0.59% |
| 2012 | PEG | 58.20% | 41.80% | 3.64% |
| 2013 | PEG | 58.78% | 41.22% | 3.14% |
| 1996 | SRE | 78.79% | 21.21% | 9.85% |
| 1997 | SRE | 70.91% | 29.09% | 9.51% |
| 1998 | SRE | 125.81% | -25.81% | 19.81% |
| 1999 | SRE | 93.98% | 6.02% | 19.15% |
| 2000 | SRE | 48.54% | 51.46% | 12.24% |
| 2001 | SRE | 39.22% | 60.78% | 11.52% |
| 2002 | SRE | 35.84% | 64.16% | 9.78% |
| 2003 | SRE | 33.22% | 66.78% | 9.00% |
| 2004 | SRE | 25.45% | 74.55% | 4.47% |
| 2005 | SRE | 32.95% | 67.05% | 3.37% |
| 2006 | SRE | 28.37% | 71.63% | 1.58% |
| 2007 | SRE | 29.11% | 70.89% | 0.90% |
| 2008 | SRE | 30.93% | 69.07% | -0.50% |
| 2009 | SRE | 32.64% | 67.36% | -0.13% |
| 2010 | SRE | 38.81% | 61.19% | 5.64% |
| 2011 | SRE | 42.95% | 57.05% | -0.39% |
| 2012 | SRE | 55.17% | 44.83% | 1.99% |
| 2013 | SRE | 59.72% | 40.28% | 6.26% |
| 1996 | SO | 75.00% | 25.00% | -0.15% |
| 1997 | SO | 82.28% | 17.72% | 4.02% |
| 1998 | SO | 77.46% | 22.54% | 3.42% |
| 1999 | SO | 73.22% | 26.78% | 3.18% |
| 2000 | SO | 66.67% | 33.33% | 1.89% |
| 2001 | SO | 83.23% | 16.77% | 5.59% |
| 2002 | SO | 73.51% | 26.49% | 4.32% |
| 2003 | SO | 70.56% | 29.44% | 2.76% |
| 2004 | SO | 68.93% | 31.07% | 2.47% |
| 2005 | SO | 69.48% | 30.52% | 2.14% |
| 2006 | SO | 73.33% | 26.67% | 4.03% |
| 2007 | SO | 70.18% | 29.82% | 3.26% |
| 2008 | SO | 73.78% | 26.22% | 3.74% |
| 2009 | SO | 74.57% | 25.43% | 3.64% |
| 2010 | SO | 76.27% | 23.73% | 3.80% |
| 2011 | SO | 73.33% | 26.67% | 2.12% |
| 2012 | SO | 72.66% | 27.34% | 3.86% |
| 2013 | SO | 74.44% | 25.56% | 2.33% |
| 1996 | WEC | 75.76% | 24.24% | 35.15% |
| 1997 | WEC | 285.19% | -185.19% | 54.91% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1998 | WEC | 93.98% | 6.02% | 12.91% |
| 1999 | WEC | 82.98% | 17.02% | 6.72% |
| 2000 | WEC | 127.78% | -27.78% | 22.76% |
| 2001 | WEC | 43.48% | 56.52% | 9.31% |
| 2002 | WEC | 34.48% | 65.52% | 5.61% |
| 2003 | WEC | 35.40% | 64.60% | 7.54% |
| 2004 | WEC | 45.16% | 54.84% | 12.13% |
| 2005 | WEC | 34.38% | 65.63% | 8.60% |
| 2006 | WEC | 34.85% | 65.15% | 10.68% |
| 2007 | WEC | 35.21% | 64.79% | 10.73% |
| 2008 | WEC | 35.53% | 64.47% | 10.68% |
| 2009 | WEC | 42.50% | 57.50% | 10.27% |
| 2010 | WEC | 41.67% | 58.33% | 4.34% |
| 2011 | WEC | 47.71% | 52.29% | 6.93% |
| 2012 | WEC | 51.06% | 48.94% | 6.58% |
| 2013 | WEC | 57.77% | 42.23% | 6.50% |
| 1996 | XEL | 71.73% | 28.27% | 6.01% |
| 1997 | XEL | 86.96% | 13.04% | -7.15% |
| 1998 | XEL | 77.72% | 22.28% | 28.57% |
| 1999 | XEL | 101.40% | -1.40% | 33.67% |
| 2000 | XEL | 92.50% | 7.50% | 30.19% |
| 2001 | XEL | 66.08% | 33.92% | 24.32% |
| 2002 | XEL | 269.05% | -169.05% | 40.62% |
| 2003 | XEL | 60.98% | 39.02% | 3.68% |
| 2004 | XEL | 63.78% | 36.22% | 3.44% |
| 2005 | XEL | 70.83% | 29.17% | 5.48% |
| 2006 | XEL | 65.19% | 34.81% | 5.03% |
| 2007 | XEL | 67.41% | 32.59% | 6.54% |
| 2008 | XEL | 64.38% | 35.62% | 5.56% |
| 2009 | XEL | 65.10% | 34.90% | 6.41% |
| 2010 | XEL | 64.10% | 35.90% | 6.16% |
| 2011 | XEL | 59.88% | 40.12% | 5.15% |
| 2012 | XEL | 57.84% | 42.16% | 4.46% |
| 2013 | XEL | 58.12% | 41.88% | 5.29% |

Retention Ratio Regression Analysis - Mr. O'Donnell's Proxy Group

Source: Value Line

| Company | Ticker | | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1.35 | 2.48 | 2.77 | 3.08 | 2.82 | 1.89 | 2.19 | 2.65 | 2.58 | 2.63 | 2.9 | 3.38 | 3.14 | 3.13 | 3.38 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 0.30 | 1.25 | 1.45 | 1.64 | 1.72 | 1.76 | 1.76 | 1.78 | 1.84 | 1.9 | 1.96 | 2.02 | 2.08 | 2.14 | 2.24 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 22.22% | 50.40% | 52.35% | 53.25% | 60.99% | 93.12% | 80.37% | 67.17% | 71.32% | 72.24% | 67.59% | 59.76% | 66.24% | 68.37% | 66.27% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 83.70% | 11.69% | 11.19% | -8.44% | -32.98% | 15.87% | 21.00% | -2.64% | 1.94% | 10.27% | 16.55% | -7.10% | -0.32% | 7.99% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 13.03% | -0.53% | 1.33% | -1.44% | 0.64% | 9.29% | 9.42% | 3.80% | 4.27% | 5.48% | N/A | N/A | N/A | N/A | N/A |
| Alliant Energy Corporation | LNT | Earnings Per Share | 1.14 | 0.95 | 0.63 | 1.10 | 1.24 | 1.21 | 0.59 | 0.79 | 0.93 | 1.11 | 1.03 | 1.35 | 1.27 | 0.95 | 1.38 | 1.38 | 1.53 | 1.65 | 1.74 | 1.69 | 1.65 | 1.99 | 2.19 |
| | | Dividends Per Share | 0.99 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 0.50 | 0.51 | 0.53 | 0.58 | 0.64 | 0.70 | 0.75 | 0.79 | 0.85 | 0.90 | 0.94 | 1.02 | 1.10 | 1.18 | 1.26 | 1.34 |
| | | Payout Ratio | 86.78% | 105.26% | 158.73% | 91.32% | 80.97% | 82.64% | 169.49% | 63.69% | 55.14% | 47.51% | 55.83% | 47.21% | 55.12% | 78.95% | 57.45% | 61.82% | 59.02% | 56.97% | 58.62% | 65.09% | 71.52% | 63.32% | 61.19% |
| | | Annual Earnings Growth | N/A | -16.30% | -33.68% | 73.81% | 12.79% | -2.02% | -51.24% | 33.05% | 17.83% | 19.46% | -6.79% | 30.58% | -5.58% | -25.20% | 44.74% | 0.00% | 10.91% | 8.20% | 5.45% | -2.87% | -2.37% | 20.61% | 10.05% |
| | | 5yr Avg Fwd EPS Growth | 6.92% | -0.07% | 13.28% | 2.08% | 3.42% | 2.46% | 18.83% | 11.10% | 2.50% | 7.55% | 8.91% | 4.97% | 7.73% | 13.86% | 4.34% | 3.86% | 5.80% | 6.17% | N/A | N/A | N/A | N/A | N/A |
| Ameren Corporation | AEE | Earnings Per Share | 2.86 | 2.44 | 2.82 | 2.81 | 3.33 | 3.41 | 2.66 | 3.14 | 2.82 | 3.13 | 2.66 | 2.98 | 2.88 | 2.78 | 2.77 | 2.47 | 2.41 | 2.10 | 2.40 | 2.38 | 2.68 | 2.77 | 3.32 |
| | | Dividends Per Share | 2.51 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 1.54 | 1.54 | 1.56 | 1.60 | 1.60 | 1.61 | 1.66 | 1.72 | 1.78 | 1.85 |
| | | Payout Ratio | 87.76% | 104.10% | 90.07% | 90.39% | 76.28% | 74.49% | 95.49% | 80.89% | 90.07% | 81.15% | 95.49% | 85.23% | 88.19% | 55.40% | 55.60% | 63.16% | 66.39% | 76.19% | 67.08% | 69.75% | 64.18% | 64.26% | 55.72% |
| | | Annual Earnings Growth | N/A | -14.69% | 15.57% | -0.35% | 18.51% | 2.40% | -21.99% | 18.05% | -10.19% | 10.99% | -15.02% | 12.03% | -3.36% | -3.47% | -0.36% | -10.83% | -2.43% | -12.86% | 14.29% | -0.83% | 12.61% | 3.36% | 19.86% |
| | | 5yr Avg Fwd EPS Growth | 4.29% | 2.83% | 3.32% | 1.35% | -0.15% | -3.63% | 3.17% | -1.11% | 0.24% | -2.03% | -1.20% | -4.09% | -5.99% | -2.44% | -2.53% | 2.15% | 3.31% | 9.85% | N/A | N/A | N/A | N/A | N/A |
| American Electric Power Company, Inc. | AEP | Earnings Per Share | 3.14 | 3.28 | 2.81 | 2.69 | 1.04 | 3.27 | 2.86 | 2.53 | 2.61 | 2.64 | 2.86 | 2.86 | 2.99 | 2.97 | 2.60 | 3.13 | 2.98 | 3.18 | 3.34 | 3.59 | 4.23 | 3.62 | 3.90 |
| | | Dividends Per Share | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 1.65 | 1.40 | 1.42 | 1.50 | 1.58 | 1.64 | 1.64 | 1.71 | 1.85 | 1.88 | 1.95 | 2.03 | 2.15 | 2.27 | 2.39 | 2.53 |
| | | Payout Ratio | 76.43% | 73.17% | 85.41% | 89.22% | 230.77% | 73.39% | 83.92% | 65.22% | 53.64% | 53.79% | 52.45% | 55.24% | 54.85% | 55.22% | 65.77% | 59.11% | 63.09% | 61.32% | 60.78% | 59.89% | 53.66% | 66.02% | 64.87% |
| | | Annual Earnings Growth | N/A | 4.46% | -14.33% | -4.27% | -61.34% | 214.42% | -12.54% | -11.54% | 3.16% | 1.15% | 8.33% | 0.00% | 4.55% | -0.67% | -12.46% | 20.38% | -4.79% | 6.71% | 5.03% | 7.49% | 17.83% | -14.42% | 7.73% |
| | | 5yr Avg Fwd EPS Growth | 27.79% | 24.39% | 24.95% | 26.43% | 38.93% | -2.29% | 0.22% | 3.44% | 2.67% | -0.05% | 2.36% | 1.40% | 1.84% | 2.98% | 6.96% | 6.45% | 4.53% | 4.73% | N/A | N/A | N/A | N/A | N/A |
| CMS Energy Corporation | CMS | Earnings Per Share | 2.45 | 2.61 | 2.24 | 2.85 | 2.53 | 1.27 | -2.99 | -0.29 | 0.74 | 1.1 | 0.64 | 0.64 | 1.23 | 0.93 | 1.33 | 1.45 | 1.53 | 1.66 | 1.74 | 1.89 | 1.98 | 2.17 | 2.32 |
| | | Dividends Per Share | 1.02 | 1.14 | 1.26 | 1.39 | 1.46 | 1.46 | 1.09 | N/A | N/A | N/A | N/A | 0.2 | 0.36 | 0.5 | 0.66 | 0.84 | 0.96 | 1.02 | 1.08 | 1.16 | 1.24 | 1.33 | 1.43 |
| | | Payout Ratio | 41.63% | 43.68% | 56.25% | 48.77% | 57.71% | 114.96% | N/A | N/A | N/A | N/A | N/A | 31.25% | 29.27% | 53.76% | 49.62% | 57.93% | 62.75% | 61.45% | 62.07% | 61.38% | 62.63% | 61.29% | 61.64% |
| | | Annual Earnings Growth | N/A | 6.53% | -14.18% | 27.23% | -11.23% | -49.80% | -335.43% | -90.30% | -355.17% | 48.65% | -41.82% | 0.00% | 92.19% | -24.39% | 43.01% | 9.02% | 5.52% | 8.50% | 4.82% | 8.62% | 4.76% | 9.60% | 6.91% |
| | | 5yr Avg Fwd EPS Growth | -8.29% | -76.68% | -91.91% | -168.39% | -156.41% | -154.82% | -87.73% | -51.23% | 14.93% | 13.80% | 23.97% | 25.07% | 8.33% | 14.17% | 7.30% | 6.44% | 7.26% | 6.94% | N/A | N/A | N/A | N/A | N/A |
| Consolidated Edison, Inc. | ED | Earnings Per Share | N/A | 2.95 | 3.04 | 3.13 | 2.74 | 3.21 | 3.13 | 2.83 | 2.32 | 2.99 | 2.95 | 3.48 | 3.36 | 3.14 | 3.47 | 3.57 | 3.86 | 3.93 | 3.62 | 4.05 | 3.94 | 4.10 | 4.55 |
| | | Dividends Per Share | N/A | 2.10 | 2.12 | 2.14 | 2.18 | 2.20 | 2.22 | 2.24 | 2.26 | 2.28 | 2.30 | 2.32 | 2.34 | 2.36 | 2.38 | 2.40 | 2.42 | 2.46 | 2.52 | 2.60 | 2.68 | 2.76 | 2.86 |
| | | Payout Ratio | N/A | 71.19% | 69.74% | 68.37% | 79.56% | 68.54% | 70.93% | 79.15% | 97.41% | 76.25% | 77.97% | 66.67% | 69.64% | 75.16% | 68.59% | 67.23% | 62.69% | 62.60% | 69.61% | 64.20% | 68.02% | 67.32% | 62.86% |
| | | Return on Common Equity | N/A | N/A | 3.05% | 2.96% | -12.46% | 17.15% | -2.49% | -9.58% | -18.02% | 28.88% | -1.34% | 17.97% | -3.45% | -6.55% | 10.51% | 2.88% | 8.12% | 1.81% | -7.89% | 11.88% | -2.72% | 4.06% | 10.98% |
| | | 5yr Avg Fwd EPS Growth | N/A | 1.64% | -0.88% | -5.08% | 3.19% | -0.51% | 3.58% | 4.81% | 7.10% | 3.43% | 4.27% | 2.30% | 3.36% | 3.09% | 3.36% | 2.24% | 1.43% | 3.26% | N/A | N/A | N/A | N/A | N/A |
| Dominion Energy Inc | D | Earnings Per Share | N/A | 1.50 | 0.86 | 1.50 | 1.25 | 1.49 | 2.41 | 1.96 | 2.13 | 1.50 | 2.40 | 2.13 | 3.04 | 2.64 | 2.89 | 2.76 | 2.75 | 3.09 | 3.05 | 3.20 | 3.44 | 3.53 | 3.25 |
| | | Dividends Per Share | N/A | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.30 | 1.34 | 1.38 | 1.46 | 1.58 | 1.75 | 1.83 | 1.97 | 2.11 | 2.25 | 2.40 | 2.59 | 2.80 | 3.04 | 3.34 |
| | | Payout Ratio | N/A | 86.00% | 150.00% | 86.00% | 103.20% | 86.58% | 53.53% | 65.82% | 61.03% | 89.33% | 57.50% | 68.54% | 51.97% | 66.29% | 63.32% | 71.38% | 76.73% | 72.82% | 78.69% | 80.94% | 81.40% | 86.12% | 102.77% |
| | | Annual Earnings Growth | N/A | N/A | -42.67% | 74.42% | -16.67% | 19.20% | 61.74% | -18.67% | 8.67% | -29.58% | 60.00% | -11.25% | 42.72% | -13.16% | 9.47% | -4.50% | -0.36% | 12.36% | -1.29% | 4.92% | 7.50% | 2.62% | -7.93% |
| | | 5yr Avg Fwd EPS Growth | N/A | 19.21% | 24.00% | 10.86% | 8.27% | 16.43% | 1.83% | 14.11% | 9.75% | 17.56% | 4.66% | 6.83% | 0.76% | 3.14% | 2.23% | 4.62% | 5.22% | 1.16% | N/A | N/A | N/A | N/A | N/A |
| Duke Energy Corporation | DUK | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2.76 | 3.6 | 3.03 | 3.39 | 4.02 | 4.14 | 3.71 | 3.98 | 4.13 | 4.1 | 3.71 | 4.22 | 4.13 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2.58 | 2.7 | 2.82 | 2.91 | 2.97 | 3.03 | 3.09 | 3.15 | 3.24 | 3.36 | 3.49 | 3.64 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 71.67% | 89.11% | 83.19% | 72.39% | 71.74% | 81.67% | 77.64% | 76.27% | 79.02% | 90.57% | 82.70% | 88.14% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 30.43% | -15.83% | 11.88% | 18.58% | 2.99% | -10.39% | 7.28% | 3.77% | -0.73% | -9.51% | 13.75% | -2.13% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 9.61% | 1.45% | 6.07% | 4.45% | 0.58% | -1.92% | 1.03% | 2.91% | N/A | N/A | N/A | N/A | N/A |
| Edison International | EIX | Earnings Per Share | 1.64 | 1.75 | 1.86 | 2.03 | N/A | 1.30 | 1.82 | 2.38 | 0.69 | 3.34 | 3.28 | 3.32 | 3.68 | 3.24 | 3.35 | 3.23 | 4.55 | 3.78 | 4.33 | 4.15 | 3.94 | 4.51 | -1.26 |
| | | Dividends Per Share | 1.00 | 1.00 | 1.04 | 1.08 | 0.83 | N/A | N/A | N/A | 0.80 | 1.02 | 1.10 | 1.18 | 1.23 | 1.25 | 1.27 | 1.29 | 1.31 | 1.37 | 1.48 | 1.73 | 1.98 | 2.23 | 2.43 |
| | | Payout Ratio | 60.98% | 57.14% | 55.91% | 53.20% | N/A | N/A | N/A | N/A | 115.94% | 30.54% | 33.54% | 35.54% | 33.42% | 38.58% | 37.91% | 39.94% | 28.79% | 36.24% | 34.18% | 41.69% | 50.25% | 49.45% | N/A |
| | | Return on Common Equity | N/A | 6.71% | 6.29% | 9.14% | N/A | N/A | 40.00% | 30.77% | -71.01% | 384.06% | -1.80% | 1.22% | 10.84% | -11.96% | 3.40% | -3.58% | 40.87% | -16.92% | 14.55% | -4.16% | -5.06% | 14.47% | -127.94% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | 76.40% | 68.65% | 64.66% | 76.47% | 0.34% | -0.02% | 7.91% | 2.36% | 7.66% | 6.15% | 5.86% | 0.58% | -21.63% | N/A | N/A | N/A | N/A | N/A |
| Entergy Corporation | ETR | Earnings Per Share | N/A | 2.25 | 2.22 | 2.25 | 2.97 | 3.08 | 3.68 | 3.69 | 3.93 | 4.40 | 5.36 | 5.60 | 6.20 | 6.30 | 6.66 | 7.55 | 6.02 | 4.96 | 5.77 | 5.81 | 6.88 | 5.19 | 5.88 |
| | | Dividends Per Share | N/A | 1.80 | 1.50 | 1.20 | 1.22 | 1.28 | 1.34 | 1.60 | 1.89 | 2.16 | 2.16 | 2.58 | 3.00 | 3.00 | 3.24 | 3.32 | 3.32 | 3.32 | 3.32 | 3.34 | 3.42 | 3.50 | 3.58 |
| | | Payout Ratio | N/A | 80.00% | 67.57% | 53.33% | 41.08% | 41.56% | 36.41% | 43.36% | 48.09% | 49.09% | 40.30% | 46.07% | 48.39% | 47.62% | 48.65% | 43.97% | 55.15% | 66.94% | 57.54% | 57.49% | 49.71% | 67.44% | 60.88% |
| | | Return on Common Equity | N/A | N/A | -1.33% | 1.35% | 32.00% | 3.70% | 19.48% | 0.27% | 6.50% | 11.96% | 21.82% | 4.48% | 10.71% | 1.61% | 5.71% | 13.36% | -20.26% | -17.61% | 16.33% | 0.69% | 18.42% | -24.56% | 13.29% |
| | | 5yr Avg Fwd EPS Growth | N/A | 11.04% | 11.36% | 12.39% | 8.38% | 12.01% | 9.01% | 11.09% | 10.12% | 8.87% | 7.18% | 2.23% | -3.44% | -0.49% | -1.50% | -0.49% | -1.35% | 4.83% | N/A | N/A | N/A | N/A | N/A |
| Eversource Energy | ES | Earnings Per Share | N/A | -1.05 | -0.36 | -1.14 | -0.20 | 1.37 | 1.08 | 1.24 | 0.91 | 0.98 | 0.82 | 1.59 | 1.86 | 1.91 | 2.10 | 2.22 | 1.89 | 2.49 | 2.58 | 2.76 | 2.96 | 3.11 | 3.25 |
| | | Dividends Per Share | N/A | 0.25 | N/A | 0.10 | 0.40 | 0.45 | 0.53 | 0.58 | 0.63 | 0.68 | 0.73 | 0.78 | 0.83 | 0.95 | 1.03 | 1.10 | 1.32 | 1.47 | 1.57 | 1.67 | 1.78 | 1.90 | 2.02 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | 32.85% | 49.07% | 46.77% | 69.23% | 69.39% | 89.02% | 49.06% | 44.62% | 49.74% | 49.05% | 49.55% | 69.84% | 59.04% | 60.85% | 60.51% | 60.14% | 61.09% | 62.15% |
| | | Return on Common Equity | N/A | N/A | -65.71% | 216.67% | -82.46% | -785.00% | -21.17% | 14.81% | -26.61% | 7.69% | -16.33% | 93.90% | 16.98% | 2.69% | 9.95% | 5.71% | -14.86% | 31.75% | 3.61% | 6.98% | 7.25% | 5.07% | 4.50% |
| | | 5yr Avg Fwd EPS Growth | N/A | -147.53% | -131.43% | -180.08% | -162.05% | -8.32% | 14.69% | 15.13% | 20.99% | 21.44% | 25.85% | 4.09% | 7.05% | 7.23% | 6.64% | 6.94% | 10.93% | 5.48% | N/A | N/A | N/A | N/A | N/A |
| Hawaiian Electric Industries, Inc. | HE | Earnings Per Share | 1.30 | 1.38 | 1.48 | 1.45 | 1.27 | 1.60 | 1.62 | 1.58 | 1.36 | 1.46 | 1.33 | 1.11 | 1.07 | 0.91 | 1.21 | 1.44 | 1.67 | 1.62 | 1.64 | 1.50 | 2.29 | 1.64 | 1.85 |
| | | Dividends Per Share | 1.21 | 1.22 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| | | Payout Ratio | 93.08% | 88.41% | 83.78% | 85.52% | 97.64% | 77.50% | 76.54% | 78.48% | 91.18% | 84.93% | 93.23% | 111.71% | 115.89% | 136.26% | 102.48% | 86.11% | 74.25% | 76.54% | 75.61% | 82.67% | 54.15% | 75.61% | 67.03% |
| | | Annual Earnings Growth | N/A | 6.15% | 7.25% | -2.03% | -12.41% | 25.98% | 1.25% | -2.47% | -13.92% | 7.35% | -8.90% | -16.54% | -3.60% | -14.95% | 32.97% | 19.01% | 15.97% | -2.99% | 1.23% | -8.54% | 52.67% | -28.38% | 12.80% |
| | | 5yr Avg Fwd EPS Growth | 4.99% | 4.01% | 2.06% | -0.31% | 3.64% | -3.34% | -6.90% | -7.12% | -7.33% | -2.21% | 3.38% | 9.88% | 10.00% | 13.24% | 4.94% | 11.67% | 2.80% | 5.96% | N/A | N/A | N/A | N/A | N/A |
| IDACORP, Inc. | IDA | Earnings Per Share | 2.21 | 2.32 | 2.37 | 2.43 | 3.50 | 3.35 | 1.63 | 0.96 | 1.90 | 1.75 | 2.35 | 1.86 | 2.18 | 2.64 | 2.95 | 3.36 | 3.37 | 3.64 | 3.85 | 3.87 | 3.94 | 4.21 | 4.49 |
| | | Dividends Per Share | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.70 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.37 | 1.57 | 1.76 | 1.92 | 2.08 | 2.24 | 2.40 |
| | | Payout Ratio | 84.16% | 80.17% | 78.48% | 76.54% | 53.14% | 55.52% | 114.11% | 177.08% | 63.16% | 68.57% | 51.06% | 64.52% | 55.05% | 45.45% | 40.68% | 35.71% | 40.65% | 43.13% | 45.71% | 49.61% | 52.79% | 53.21% | 53.45% |
| | | Return on Common Equity | N/A | 4.98% | 2.16% | 2.53% | 44.03% | -4.29% | -51.34% | -41.10% | 97.92% | -7.89% | 34.29% | -20.85% | 17.20% | 21.10% | 11.74% | 13.90% | 0.30% | 8.01% | 5.77% | 0.52% | 1.81% | 6.85% | 6.65% |
| | | 5yr Avg Fwd EPS Growth | 9.88% | -1.38% | -10.03% | 9.04% | -1.34% | 6.37% | 12.47% | 24.13% | 8.77% | 12.70% | 8.62% | 12.85% | 11.01% | 7.94% | 5.70% | 3.28% | 4.59% | 4.32% | N/A | N/A | N/A | N/A | N/A |
| MGE Energy, Inc. | MGEE | Earnings Per Share | N/A | N/A | 0.92 | 0.99 | 1.11 | 1.08 | 1.13 | 1.14 | 1.18 | 1.05 | 1.37 | 1.51 | 1.59 | 1.47 | 1.67 | 1.76 | 1.86 | 2.16 | 2.32 | 2.06 | 2.18 | 2.20 | 2.43 |
| | | Dividends Per Share | N/A | N/A | 0.86 | 0.87 | 0.88 | 0.89 | 0.89 | 0.90 | 0.91 | 0.92 | 0.93 | 0.94 | 0.96 | 0.97 | 0.99 | 1.01 | 1.04 | 1.07 | 1.11 | 1.16 | 1.21 | 1.26 | 1.32 |
| | | Payout Ratio | N/A | N/A | 93.48% | 87.88% | 79.28% | 82.41% | 78.76% | 78.95% | 77.12% | 87.62% | 67.88% | 62.25% | 60.38% | 65.99% | 59.28% | 57.39% | 55.91% | 49.54% | 47.84% | 56.31% | 55.50% | 57.27% | 54.32% |
| | | Return on Common Equity | N/A | N/A | N/A | 7.61% | 12.12% | -2.70% | 4.63% | 0.88% | 3.51% | -11.02% | 30.48% | 10.22% | 5.30% | -7.55% | 13.61% | 5.39% | 5.68% | 16.13% | 7.41% | -11.21% | 5.83% | 0.92% | 10.45% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | 4.51% | 3.69% | -0.94% | 5.70% | 6.81% | 7.70% | 5.49% | 10.41% | 5.39% | 4.49% | 6.65% | 9.64% | 4.68% | 4.77% | 3.81% | 2.68% | N/A | N/A | N/A | N/A | N/A |
| Nextera Energy Inc. | NEE | Earnings Per Share | 1.67 | 1.79 | 1.93 | 2.04 | 2.07 | 2.31 | 2.01 | 2.45 | 2.46 | 2.32 | 3.23 | 3.27 | 4.07 | 3.97 | 4.74 | 4.82 | 4.56 | 4.83 | 5.60 | 6.06 | 5.78 | 6.50 | 6.67 |
| | | Dividends Per Share | 0.92 | 0.96 | 1.00 | 1.04 | 1.08 | 1.12 | 1.16 | 1.20 | 1.30 | 1.42 | 1.50 | 1.64 | 1.78 | 1.89 | 2.00 | 2.20 | 2.40 | 2.64 | 2.90 | 3.08 | 3.48 | 3.93 | 4.44 |
| | | Payout Ratio | 55.26% | 53.63% | 51.81% | 50.98% | 52.17% | 48.48% | 57.71% | 48.98% | 52.85% | 61.21% | 46.44% | 50.15% | 43.73% | 47.61% | 42.19% | 45.64% | 52.63% | 54.66% | 51.79% | 50.83% | 60.21% | 60.46% | 66.57% |
| | | Annual Earnings Growth | N/A | 7.51% | 7.82% | 5.70% | 1.47% | 11.59% | -12.99% | 21.89% | 0.41% | -5.69% | 39.22% | 1.24% | 24.46% | -2.46% | 19.40% | 1.69% | -5.39% | 5.92% | 15.94% | 8.21% | -4.62% | 12.46% | 2.62% |
| | | 5yr Avg Fwd EPS Growth | 6.82% | 2.72% | 5.53% | 4.48% | 3.04% | 8.57% | 11.41% | 11.93% | 11.36% | 16.37% | 8.87% | 7.54% | 3.83% | 7.51% | 5.27% | 4.01% | 7.58% | 6.92% | N/A | N/A | N/A | N/A | N/A |
| NorthWestern Corporation | NWE | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -14.32 | 1.71 | 1.31 | 1.44 | 1.77 | 2.02 | 2.14 | 2.53 | 2.26 | 2.46 | 2.99 | 2.9 | 3.39 | 3.34 | 3.4 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1 | 1.24 | 1.28 | 1.32 | 1.34 | 1.36 | 1.44 | 1.48 | 1.52 | 1.6 | 1.92 | 2 | 2.1 | 2.2 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 58.48% | 94.66% | 88.89% | 74.58% | 66.34% | 63.55% | 56.92% | 65.49% | 61.79% | 53.51% | 66.21% | 59.00% | 62.87% | 64.71% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -111.94% | -23.39% | 9.92% | 22.92% | 14.12% | 5.94% | 18.22% | -10.67% | 8.85% | 21.54% | -3.01% | 16.90% | -1.47% | 1.80% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -17.67% | 5.90% | 14.23% | 10.11% | 7.29% | 8.78% | 6.99% | 6.72% | 8.56% | 7.15% | N/A | N/A | N/A | N/A | N/A |
| OGE Energy Corp. | OGE | Earnings Per Share | N/A | N/A | 1.02 | 0.97 | 0.95 | 0.65 | 0.72 | 0.87 | 0.89 | 0.92 | 1.23 | 1.32 | 1.25 | 1.33 | 1.50 | 1.73 | 1.79 | 1.94 | 1.98 | 1.69 | 1.69 | 1.92 | 2.12 |
| | | Dividends Per Share | N/A | N/A | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.68 | 0.70 | 0.71 | 0.73 | 0.76 | 0.80 | 0.85 | 0.95 | 1.05 | 1.16 | 1.27 | 1.40 |
| | | Payout Ratio | N/A | N/A | 65.69% | 69.07% | 70.53% | 103.08% | 93.06% | 77.01% | 75.28% | 72.83% | 54.47% | 51.52% | 56.00% | 53.38% | 48.67% | 43.93% | 44.69% | 43.81% | 47.98% | 62.13% | 68.64% | 66.15% | 66.04% |
| | | Annual Earnings Growth | N/A | N/A | N/A | -4.90% | -2.06% | -31.58% | 10.77% | 20.83% | 2.30% | 3.37% | 33.70% | 7.32% | -5.30% | 6.40% | 12.78% | 15.33% | 3.47% | 8.38% | 2.06% | -14.65% | 0.00% | 13.61% | 10.42% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | -1.39% | 0.05% | 1.14% | 14.19% | 13.50% | 8.28% | 9.10% | 10.98% | 7.31% | 6.54% | 9.27% | 8.41% | 2.92% | -0.15% | 1.88% | 2.29% | N/A | N/A | N/A | N/A | N/A |
| Otter Tail Corporation | OTTR | Earnings Per Share | 1.24 | 1.29 | 1.29 | 1.45 | 1.60 | 1.68 | 1.79 | 1.51 | 1.50 | 1.78 | 1.69 | 1.78 | 1.09 | 0.71 | 0.38 | 0.45 | 1.05 | 1.37 | 1.55 | 1.56 | 1.60 | 1.86 | 2.06 |
| | | Dividends Per Share | 0.90 | 0.93 | 0.96 | 0.99 | 1.02 | 1.04 | 1.06 | 1.08 | 1.10 | 1.12 | 1.15 | 1.17 | 1.19 | 1.19 | 1.19 | 1.19 | 1.19 | 1.19 | 1.21 | 1.23 | 1.25 | 1.28 | 1.34 |
| | | Payout Ratio | 72.58% | 72.09% | 74.42% | 68.28% | 63.75% | 61.90% | 59.22% | 71.52% | 73.33% | 62.92% | 68.05% | 65.73% | 109.17% | 167.61% | 313.16% | 264.44% | 113.33% | 86.86% | 78.06% | 78.85% | 78.13% | 68.82% | 65.05% |
| | | Annual Earnings Growth | N/A | 4.03% | 0.00% | 12.40% | 10.34% | 5.00% | 6.55% | -15.64% | -0.66% | 18.67% | -5.06% | 5.33% | -38.76% | -34.86% | -46.48% | 18.42% | 133.33% | 30.48% | 13.14% | 0.65% | 2.56% | 16.25% | 10.75% |
| | | 5yr Avg Fwd EPS Growth | 6.36% | 6.86% | 3.73% | 1.12% | 2.78% | 0.77% | 0.53% | -4.10% | -10.94% | -23.97% | -19.27% | 6.33% | 20.18% | 29.78% | 39.20% | 36.03% | 12.61% | 8.67% | N/A | N/A | N/A | N/A | N/A |
| Pinnacle West Capital Corporation | PNW | Earnings Per Share | 2.47 | 2.76 | 2.85 | 3.18 | 3.35 | 3.68 | 2.53 | 2.52 | 2.58 | 2.24 | 3.17 | 2.96 | 2.12 | 2.26 | 3.08 | 2.99 | 3.50 | 3.66 | 3.58 | 3.92 | 3.95 | 4.43 | 4.54 |
| | | Dividends Per Share | 1.03 | 1.13 | 1.23 | 1.33 | 1.43 | 1.53 | 1.63 | 1.73 | 1.83 | 1.93 | 2.03 | 2.10 | 2.10 | 2.10 | 2.10 | 2.10 | 2.67 | 2.23 | 2.33 | 2.44 | 2.56 | 2.70 | 2.87 |
| | | Payout Ratio | 41.70% | 40.94% | 43.16% | 41.82% | 42.69% | 41.58% | 64.43% | 68.65% | 70.93% | 86.16% | 64.04% | 70.95% | 99.06% | 92.92% | 68.18% | 70.23% | 76.29% | 60.93% | 65.08% | 62.24% | 64.81% | 60.95% | 63.22% |
| | | Annual Earnings Growth | N/A | 11.74% | 3.26% | 11.58% | 5.35% | 9.85% | -31.25% | -0.40% | 2.38% | -13.18% | 41.52% | -6.62% | -28.38% | 6.60% | 36.28% | -2.92% | 17.06% | 4.57% | -2.19% | 9.50% | 0.77% | 12.15% | 2.48% |
| | | 5yr Avg Fwd EPS Growth | 8.36% | -0.24% | -0.97% | -2.81% | -6.52% | -0.18% | 4.74% | -0.86% | -0.01% | 9.88% | 0.99% | 5.73% | 12.32% | 10.56% | 5.20% | 5.94% | 4.96% | 4.54% | N/A | N/A | N/A | N/A | N/A |
| PNM Resources, Inc. | PNM | Earnings Per Share | 1.15 | 1.25 | 1.50 | 1.29 | 1.55 | 2.61 | 1.07 | 1.15 | 1.43 | 1.56 | 1.72 | 0.76 | 0.11 | 0.58 | 0.87 | 1.08 | 1.31 | 1.41 | 1.45 | 1.64 | 1.65 | 1.92 | 1.66 |
| | | Dividends Per Share | 0.24 | 0.42 | 0.51 | 0.53 | 0.53 | 0.53 | 0.57 | 0.61 | 0.63 | 0.79 | 0.86 | 0.91 | 0.61 | 0.50 | 0.50 | 0.50 | 0.58 | 0.68 | 0.76 | 0.80 | 0.88 | 0.99 | 1.09 |
| | | Payout Ratio | 20.87% | 33.60% | 34.00% | 41.09% | 34.19% | 20.31% | 53.27% | 53.04% | 44.06% | 50.64% | 50.00% | 119.74% | 554.55% | 86.21% | 57.47% | 46.30% | 44.27% | 48.23% | 52.41% | 48.78% | 53.33% | 51.56% | 65.66% |
| | | Annual Earnings Growth | N/A | 8.70% | 20.00% | -14.00% | 20.16% | 68.39% | -59.00% | 7.48% | 24.35% | 9.09% | 10.26% | -55.81% | -85.53% | 427.27% | 50.00% | 24.14% | 21.30% | 7.63% | 2.84% | 13.10% | 0.61% | 16.36% | -13.54% |
| | | 5yr Avg Fwd EPS Growth | 20.65% | 7.11% | 4.60% | 12.27% | 10.06% | -1.57% | -0.93% | -19.53% | 61.06% | 69.24% | 72.01% | 87.44% | 106.07% | 21.18% | 13.80% | 9.10% | 8.11% | 3.87% | N/A | N/A | N/A | N/A | N/A |
| Portland General Electric Company | POR | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1.02 | 1.14 | 2.33 | 1.39 | 1.31 | 1.66 | 1.95 | 1.87 | 1.77 | 2.18 | 2.04 | 2.16 | 2.29 | 2.37 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 0.68 | 0.93 | 0.97 | 1.01 | 1.04 | 1.06 | 1.08 | 1.10 | 1.12 | 1.18 | 1.26 | 1.34 | 1.43 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 59.65% | 39.91% | 69.78% | 77.10% | 62.65% | 54.36% | 57.75% | 62.15% | 51.38% | 57.84% | 58.33% | 58.52% | 60.34% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 11.76% | 104.39% | -40.34% | -5.76% | 26.72% | 17.47% | -4.10% | -5.35% | 23.16% | -6.42% | 5.88% | 6.02% | 3.49% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 19.35% | 20.49% | -1.20% | 5.80% | 11.58% | 4.95% | 2.63% | 4.66% | 6.43% | N/A | N/A | N/A | N/A | N/A |
| Public Service Enterprise Group Incorporated | PEG | Earnings Per Share | N/A | 1.21 | 1.40 | 1.56 | 1.78 | 1.85 | 1.88 | 1.88 | 1.52 | 1.79 | 1.85 | 2.59 | 2.90 | 3.08 | 3.07 | 3.11 | 2.44 | 2.45 | 2.99 | 3.30 | 2.83 | 2.82 | 2.76 |
| | | Dividends Per Share | N/A | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.10 | 1.12 | 1.14 | 1.17 | 1.29 | 1.33 | 1.37 | 1.37 | 1.42 | 1.44 | 1.48 | 1.56 | 1.64 | 1.72 | 1.80 |
| | | Payout Ratio | N/A | 89.26% | 77.14% | 69.23% | 60.67% | 58.38% | 57.45% | 57.45% | 72.37% | 62.57% | 61.62% | 45.17% | 44.48% | 43.18% | 44.63% | 44.05% | 58.20% | 58.78% | 49.50% | 47.27% | 57.95% | 60.99% | 65.22% |
| | | Return on Common Equity | N/A | N/A | 15.70% | 11.43% | 14.10% | 3.93% | 1.62% | 0.00% | -19.15% | 17.76% | 3.35% | 40.00% | 11.97% | 6.21% | -0.32% | 1.30% | -21.54% | 0.41% | 22.04% | 10.37% | -14.24% | -0.35% | -2.13% |
| | | 5yr Avg Fwd EPS Growth | N/A | 9.36% | 6.22% | 0.10% | 0.83% | 0.72% | 8.39% | 10.79% | 15.86% | 12.24% | 11.83% | -0.48% | -2.79% | 0.38% | 2.52% | -0.59% | 3.64% | 3.14% | N/A | N/A | N/A | N/A | N/A |
| Sempra Energy | SRE | Earnings Per Share | 1.98 | 2.20 | 1.24 | 1.66 | 2.06 | 2.55 | 2.79 | 3.01 | 3.93 | 3.52 | 4.23 | 4.26 | 4.43 | 4.78 | 4.02 | 4.47 | 4.35 | 4.22 | 4.63 | 5.23 | 4.24 | 4.63 | 5.48 |
| | | Dividends Per Share | 1.56 | 1.56 | 1.56 | 1.56 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.16 | 1.20 | 1.24 | 1.37 | 1.56 | 1.56 | 1.92 | 2.40 | 2.52 | 2.64 | 2.80 | 3.02 | 3.29 | 3.58 |
| | | Payout Ratio | 78.79% | 70.91% | 125.81% | 93.98% | 48.54% | 39.22% | 35.84% | 33.22% | 25.45% | 32.95% | 28.37% | 29.11% | 30.93% | 32.64% | 38.81% | 42.95% | 55.17% | 59.72% | 57.02% | 53.54% | 71.23% | 71.06% | 65.33% |
| | | Return on Common Equity | N/A | 11.11% | -43.64% | 33.87% | 24.10% | 23.79% | 9.41% | 7.89% | 30.56% | -10.43% | 20.17% | 0.71% | 3.99% | 7.90% | -15.90% | 11.19% | -2.68% | -2.99% | 9.72% | 12.96% | -18.93% | 9.20% | 18.36% |
| | | 5yr Avg Fwd EPS Growth | 9.85% | 9.51% | 19.81% | 19.15% | 12.24% | 11.52% | 9.78% | 9.00% | 4.47% | 3.37% | 1.58% | 0.90% | -0.50% | -0.13% | 5.64% | -0.39% | 1.99% | 6.26% | N/A | N/A | N/A | N/A | N/A |
| Southern Company | SO | Earnings Per Share | 1.68 | 1.58 | 1.73 | 1.83 | 2.01 | 1.61 | 1.85 | 1.97 | 2.06 | 2.13 | 2.10 | 2.28 | 2.25 | 2.32 | 2.36 | 2.55 | 2.67 | 2.70 | 2.77 | 2.84 | 2.83 | 3.21 | 3.00 |
| | | Dividends Per Share | 1.26 | 1.30 | 1.34 | 1.34 | 1.34 | 1.34 | 1.36 | 1.39 | 1.42 | 1.48 | 1.54 | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 1.94 | 2.01 | 2.08 | 2.15 | 2.22 | 2.30 | 2.38 |
| | | Payout Ratio | 75.00% | 82.28% | 77.46% | 73.22% | 66.67% | 83.23% | 73.51% | 70.56% | 68.93% | 69.48% | 73.33% | 70.18% | 73.78% | 74.57% | 76.27% | 73.33% | 72.66% | 74.44% | 75.09% | 75.70% | 78.45% | 71.65% | 79.33% |
| | | Annual Earnings Growth | N/A | -5.95% | 9.49% | 5.78% | 9.84% | -19.90% | 14.91% | 6.49% | 4.57% | 3.40% | -1.41% | 8.57% | -1.32% | 3.11% | 1.72% | 8.05% | 4.71% | 1.12% | 2.59% | 2.53% | -0.35% | 13.43% | -6.54% |
| | | 5yr Avg Fwd EPS Growth | -0.15% | 4.02% | 3.42% | 3.18% | 1.89% | 5.59% | 4.32% | 2.76% | 2.47% | 2.14% | 4.03% | 3.26% | 3.74% | 3.64% | 3.80% | 2.12% | 3.86% | 2.33% | N/A | N/A | N/A | N/A | N/A |
| WEC Energy Group | WEC | Earnings Per Share | 0.99 | 0.27 | 0.83 | 0.94 | 0.54 | 0.92 | 1.16 | 1.13 | 0.93 | 1.28 | 1.32 | 1.42 | 1.52 | 1.6 | 1.92 | 2.18 | 2.35 | 2.51 | 2.59 | 2.34 | 2.96 | 3.14 | 3.34 |
| | | Dividends Per Share | 0.75 | 0.77 | 0.78 | 0.78 | 0.69 | 0.40 | 0.40 | 0.40 | 0.42 | 0.44 | 0.46 | 0.50 | 0.54 | 0.68 | 0.80 | 1.04 | 1.20 | 1.45 | 1.56 | 1.74 | 1.98 | 2.08 | 2.21 |
| | | Payout Ratio | 75.76% | 285.19% | 93.98% | 82.98% | 127.78% | 43.48% | 34.48% | 35.40% | 45.16% | 34.38% | 34.85% | 35.21% | 35.53% | 42.50% | 41.67% | 47.71% | 51.06% | 57.77% | 60.23% | 74.36% | 66.89% | 66.24% | 66.17% |
| | | Annual Earnings Growth | N/A | -72.73% | 207.41% | 13.25% | -42.55% | 70.37% | 26.09% | -2.59% | -17.70% | 37.63% | 3.13% | 7.58% | 7.04% | 5.26% | 20.00% | 13.54% | 7.80% | 6.81% | 3.19% | -9.65% | 26.50% | 6.08% | 6.37% |
| | | 5yr Avg Fwd EPS Growth | 35.15% | 54.91% | 12.91% | 6.72% | 22.76% | 9.31% | 5.61% | 7.54% | 12.13% | 8.60% | 10.68% | 10.73% | 10.68% | 10.27% | 4.34% | 6.93% | 6.58% | 6.50% | N/A | N/A | N/A | N/A | N/A |
| Xcel Energy Inc. | XEL | Earnings Per Share | 1.91 | 1.61 | 1.84 | 1.43 | 1.60 | 2.27 | 0.42 | 1.23 | 1.27 | 1.20 | 1.35 | 1.35 | 1.46 | 1.49 | 1.56 | 1.72 | 1.85 | 1.91 | 2.03 | 2.10 | 2.21 | 2.30 | 2.47 |
| | | Dividends Per Share | 1.37 | 1.40 | 1.43 | 1.45 | 1.48 | 1.50 | 1.13 | 0.75 | 0.81 | 0.85 | 0.88 | 0.91 | 0.94 | 0.97 | 1.00 | 1.03 | 1.07 | 1.11 | 1.20 | 1.28 | 1.36 | 1.44 | 1.52 |
| | | Payout Ratio | 71.73% | 86.96% | 77.72% | 101.40% | 92.50% | 66.08% | 269.05% | 60.98% | 63.78% | 70.83% | 65.19% | 67.41% | 64.38% | 65.10% | 64.10% | 59.88% | 57.84% | 58.12% | 59.11% | 60.95% | 61.54% | 62.61% | 61.54% |
| | | Annual Earnings Growth | N/A | -15.71% | 14.29% | -22.28% | 11.89% | 41.88% | -81.50% | 192.86% | 3.25% | -5.51% | 12.50% | 0.00% | 8.15% | 2.05% | 4.70% | 10.26% | 7.56% | 3.24% | 6.28% | 3.45% | 5.24% | 4.07% | 7.39% |
| | | 5yr Avg Fwd EPS Growth | 6.01% | -7.15% | 28.57% | 33.67% | 30.19% | 24.32% | 40.62% | 3.68% | 3.44% | 5.48% | 5.03% | 6.54% | 5.56% | 6.41% | 6.16% | 5.15% | 4.46% | 5.29% | N/A | N/A | N/A | N/A | N/A |

Retention Growth Estimate Vs. Value Line EPS Growth Estimate

| Company | Ticker | [1] Actual/ Projected Earnings per share 2019 | [2] Actual/ Projected Dividend per share 2019 | [3] Retention Ratio (B) | [4] Projected Book Value per Share 2019 | [5] Return on Book Value (R) | [6] B x R | [7] Projected Common Shares Outstanding 2019 | [8] Projected Common Shares Outstanding (3-5 Year) | [9] Common Shares Growth Rate | [10] 2019 High Price | [11] 2019 Low Price | [12] 2019 price midpoint | [13] Market/ Book Ratio | [14] "S" | [15] "V" | [16] S x V | [17] BR + SV | 2019 Value Line Projected EPS Growth | Sustainable Growth Minus EPS Growth | Actual 2018 EPS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 3.33 | 2.35 | 29.43% | 43.17 | 7.71% | 2.27% | 51.70 | 53.00 | 0.62% | $ 88.60 | $ 72.50 | $ 80.55 | 1.87 | 1.16% | 46.41% | 0.54% | 2.81% | -1.48% | 4.29% | 3.38 |
| Alliant Energy Corporation | LNT | 2.33 | 1.42 | 39.06% | 21.24 | 10.97% | 4.28% | 245.02 | 260.00 | 1.49% | $ 54.60 | $ 40.80 | $ 47.70 | 2.25 | 3.36% | 55.47% | 1.86% | 6.15% | 6.39% | -0.25% | 2.19 |
| American Electric Power Company, Inc. | AEP | 4.08 | 2.71 | 33.58% | 39.73 | 10.27% | 3.45% | 494.17 | 530.00 | 1.77% | $ 96.20 | $ 72.30 | $ 84.25 | 2.12 | 3.74% | 52.84% | 1.98% | 5.43% | 4.62% | 0.81% | 3.90 |
| Ameren Corporation | AEE | 3.35 | 1.92 | 42.69% | 32.73 | 10.24% | 4.37% | 246.20 | 275.00 | 2.80% | $ 80.90 | $ 63.10 | $ 72.00 | 2.20 | 6.17% | 54.54% | 3.36% | 7.73% | 0.90% | 6.83% | 3.32 |
| CMS Energy Corporation | CMS | 2.39 | 1.53 | 35.98% | 17.68 | 13.52% | 4.86% | 283.86 | 300.00 | 1.39% | $ 65.30 | $ 48.00 | $ 56.65 | 3.20 | 4.46% | 68.79% | 3.07% | 7.93% | 3.02% | 4.92% | 2.32 |
| Consolidated Edison, Inc. | ED | 3.95 | 2.96 | 25.06% | 53.65 | 7.36% | 1.85% | 334.00 | 345.00 | 0.81% | $ 95.00 | $ 73.30 | $ 84.15 | 1.57 | 1.28% | 36.24% | 0.46% | 2.31% | -13.19% | 15.49% | 4.55 |
| Dominion Energy Inc | D | 2.15 | 3.67 | -70.70% | 34.55 | 6.22% | -4.40% | 824.00 | 865.00 | 1.22% | $ 83.90 | $ 67.40 | $ 75.65 | 2.19 | 2.67% | 54.33% | 1.45% | -2.95% | -33.85% | 30.90% | 3.25 |
| Duke Energy Corporation | DUK | 5.05 | 3.75 | 25.74% | 61.75 | 8.18% | 2.11% | 733.00 | 775.00 | 1.40% | $ 97.40 | $ 82.50 | $ 89.95 | 1.46 | 2.04% | 31.35% | 0.64% | 2.75% | 22.28% | -19.53% | 4.13 |
| Edison International | EIX | 4.65 | 2.48 | 46.67% | 37.90 | 12.27% | 5.73% | 365.00 | 385.00 | 1.34% | $ 76.40 | $ 53.40 | $ 64.90 | 1.71 | 2.30% | 41.60% | 0.96% | 6.68% | NA | NA | -1.26 |
| Entergy Corp. | ETR | 6.30 | 3.66 | 41.90% | 51.34 | 12.27% | 5.14% | 199.15 | 212.00 | 1.58% | $ 122.10 | $ 83.20 | $ 102.65 | 2.00 | 3.15% | 49.99% | 1.57% | 6.72% | 7.14% | -0.43% | 5.88 |
| Eversource Energy | ES | 3.45 | 2.14 | 37.97% | 37.70 | 9.15% | 3.47% | 324.00 | 355.00 | 2.31% | $ 86.60 | $ 63.10 | $ 74.85 | 1.99 | 4.59% | 49.63% | 2.28% | 5.75% | 6.15% | -0.40% | 3.25 |
| Hawaiian Electric Industries, Inc. | HE | 1.90 | 1.28 | 32.63% | 20.45 | 9.29% | 3.03% | 109.00 | 113.00 | 0.91% | $ 47.60 | $ 35.10 | $ 41.35 | 2.02 | 1.83% | 50.54% | 0.92% | 3.96% | 2.70% | 1.25% | 1.85 |
| IDACORP Inc. | IDA | 4.45 | 2.56 | 42.47% | 48.85 | 9.11% | 3.87% | 50.40 | 50.40 | 0.00% | $ 114.00 | $ 89.30 | $ 101.65 | 2.08 | 0.00% | 51.94% | 0.00% | 3.87% | -0.89% | 4.76% | 4.49 |
| MGE Energy Inc | MGEE | 2.51 | 1.38 | 45.02% | 24.68 | 10.17% | 4.58% | 34.67 | 34.67 | 0.00% | $ 80.80 | $ 56.70 | $ 68.75 | 2.79 | 0.00% | 64.10% | 0.00% | 4.58% | 3.29% | 1.29% | 2.43 |
| NextEra Energy, Inc. | NEE | 7.76 | 5.00 | 35.57% | 75.65 | 10.26% | 3.65% | 489.00 | 495.00 | 0.31% | $ 245.00 | $ 168.70 | $ 206.85 | 2.73 | 0.83% | 63.43% | 0.53% | 4.18% | 16.34% | -12.16% | 6.67 |
| NorthWestern Corporation | NWE | 3.55 | 2.30 | 35.21% | 40.20 | 8.83% | 3.11% | 50.50 | 51.60 | 0.54% | $ 76.70 | $ 57.30 | $ 67.00 | 1.67 | 0.90% | 40.00% | 0.36% | 3.47% | 4.41% | -0.94% | 3.40 |
| OGE Energy Corp. | OGE | 2.24 | 1.51 | 32.59% | 20.69 | 10.83% | 3.53% | 200.10 | 200.00 | -0.01% | $ 45.80 | $ 38.00 | $ 41.90 | 2.03 | -0.03% | 50.62% | -0.01% | 3.52% | 5.66% | -2.14% | 2.12 |
| Otter Tail Corporation | OTTR | 2.17 | 1.40 | 35.48% | 19.46 | 11.15% | 3.96% | 40.16 | 41.50 | 0.82% | $ 57.70 | $ 45.90 | $ 51.80 | 2.66 | 2.19% | 62.43% | 1.37% | 5.33% | 5.34% | -0.01% | 2.06 |
| Pinnacle West Capital Corporation | PNW | 4.50 | 3.04 | 32.44% | 47.70 | 9.43% | 3.06% | 113.00 | 118.00 | 1.09% | $ 99.80 | $ 81.60 | $ 90.70 | 1.90 | 2.07% | 47.41% | 0.98% | 4.04% | -0.88% | 4.92% | 4.54 |
| PNM Resources, Inc. | PNM | 2.20 | 1.18 | 46.36% | 20.80 | 10.58% | 4.90% | 79.65 | 90.00 | 3.10% | $ 53.00 | $ 39.70 | $ 46.35 | 2.23 | 6.91% | 55.12% | 3.81% | 8.71% | 32.53% | -23.82% | 1.66 |
| Portland General Electric Company | POR | 2.40 | 1.52 | 36.67% | 28.90 | 8.30% | 3.04% | 89.40 | 90.00 | 0.17% | $ 58.40 | $ 44.00 | $ 51.20 | 1.77 | 0.30% | 43.55% | 0.13% | 3.17% | 1.27% | 1.91% | 2.37 |
| Public Service Enterprie Group, Inc. | PEG | 3.70 | 1.88 | 49.19% | 29.65 | 12.48% | 6.14% | 506.00 | 506.00 | 0.00% | $ 63.90 | $ 50.00 | $ 56.95 | 1.92 | 0.00% | 47.94% | 0.00% | 6.14% | 34.06% | -27.92% | 2.76 |
| SEMPRA Energy | SRE | 5.85 | 3.87 | 33.85% | 61.25 | 9.55% | 3.23% | 290.00 | 320.00 | 2.49% | $ 154.50 | $ 106.10 | $ 130.30 | 2.13 | 5.30% | 52.99% | 2.81% | 6.04% | 6.75% | -0.71% | 5.48 |
| Southern Company | SO | 3.10 | 2.46 | 20.65% | 26.20 | 11.83% | 2.44% | 1050.00 | 1080.00 | 0.71% | $ 64.30 | $ 43.30 | $ 53.80 | 2.05 | 1.45% | 51.30% | 0.74% | 3.19% | 3.33% | -0.15% | 3.00 |
| WEC Energy Group, Inc. | WEC | 3.58 | 2.36 | 34.08% | 32.06 | 11.17% | 3.81% | 315.50 | 315.50 | 0.00% | $ 98.20 | $ 67.20 | $ 82.70 | 2.58 | 0.00% | 61.23% | 0.00% | 3.81% | 7.19% | -3.38% | 3.34 |
| Xcel Energy Inc. | XEL | 2.60 | 1.62 | 37.69% | 25.15 | 10.34% | 3.90% | 525.00 | 546.00 | 0.99% | $ 66.10 | $ 47.70 | $ 56.90 | 2.26 | 2.23% | 55.80% | 1.24% | 5.14% | 5.26% | -0.12% | 2.47 |
| | | | Average: | 32.20% | | | | | | | | | | | | | Mean: | 4.63% | 5.13% | -0.58% | |
| | | | | | | | | | | | | | | | | | Median: | 4.38% | 4.62% | -0.12% | |
| | | | | | | | | | | | | | | | | | | | Number of underestimates: | 14 | |
| | | | | | | | | | | | | | | | | | | | Number of overestimates: | 11 | |

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.33 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Equals [12] / [13]
[14] Equals [9] x [14]
[15] Equals 1 - (1 / [14])
[16] Equals [15] x [16]
[17] Equals [6] + [17]

Retention Growth Estimate Vs. Value Line EPS Growth Estimate

| Company | Ticker | [1] Projected Earnings per share (3-5 Year) | [2] Projected Dividend per share (3-5 Year) | [3] Retention Ratio (B) | [4] Projected Book Value per Share (3-5 Year) | [5] Return on Book Value (R) | [6] B x R | [7] Projected Common Shares Outstanding 2019 | [8] Projected Common Shares Outstanding (3-5 Year) | [9] Common Shares Growth Rate | [10] 2019 High Price | [11] 2019 Low Price | [12] 2019 price midpoint | [13] Projected Book Value per Share 2019 | [14] Market/ Book Ratio | [15] "S" | [16] "V" | [17] S x V | [18] 2022/2023 BR + SV | [19] 2019 BR + SV | [20] Average 2019/2022-23 BR + SV | 2023-2025/ 2022-24 Value Line Projected Annual EPS Growth | Average 2019/ 2022-23 Sustainable Growth Minus EPS Growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 4.25 | 2.85 | 32.94% | 52.50 | 8.10% | 2.67% | 51.70 | 53.00 | 0.62% | $ 88.60 | $ 72.50 | $ 80.55 | 43.17 | 1.87 | 1.16% | 46.41% | 0.54% | 3.21% | 2.81% | 3.01% | 6.29% | -3.28% |
| Alliant Energy Corporation | LNT | 2.80 | 1.74 | 37.86% | 28.80 | 9.72% | 3.68% | 245.02 | 260.00 | 1.49% | $ 54.60 | $ 40.80 | $ 47.70 | 21.24 | 2.25 | 3.36% | 55.47% | 1.86% | 5.54% | 6.15% | 5.84% | 4.70% | 1.14% |
| American Electric Power Company, Inc. | AEP | 5.00 | 3.35 | 33.00% | 50.00 | 10.00% | 3.30% | 494.17 | 530.00 | 1.77% | $ 96.20 | $ 72.30 | $ 84.25 | 39.73 | 2.12 | 3.74% | 52.84% | 1.98% | 5.28% | 5.43% | 5.35% | 5.21% | 0.14% |
| Ameren Corporation | AEE | 4.25 | 2.35 | 44.71% | 44.00 | 9.66% | 4.32% | 246.20 | 275.00 | 2.80% | $ 80.90 | $ 63.10 | $ 72.00 | 32.73 | 2.20 | 6.17% | 54.54% | 3.36% | 7.68% | 7.73% | 7.71% | 6.13% | 1.58% |
| CMS Energy Corporation | CMS | 3.25 | 2.00 | 38.46% | 25.50 | 12.75% | 4.90% | 283.86 | 300.00 | 1.39% | $ 65.30 | $ 48.00 | $ 56.65 | 17.68 | 3.20 | 4.46% | 68.79% | 3.07% | 7.97% | 7.93% | 7.95% | 7.99% | -0.04% |
| Consolidated Edison, Inc. | ED | 5.25 | 3.50 | 33.33% | 62.50 | 8.40% | 2.80% | 334.00 | 345.00 | 0.81% | $ 95.00 | $ 73.30 | $ 84.15 | 53.65 | 1.57 | 1.28% | 36.24% | 0.46% | 3.26% | 2.31% | 2.79% | 7.37% | -4.59% |
| Dominion Energy Inc | D | 5.50 | 4.15 | 24.55% | 41.00 | 13.41% | 3.29% | 824.00 | 865.00 | 1.22% | $ 83.90 | $ 67.40 | $ 75.65 | 34.55 | 2.19 | 2.67% | 54.33% | 1.45% | 4.75% | -2.95% | 0.90% | 26.47% | -25.57% |
| Duke Energy Corporation | DUK | 6.00 | 4.10 | 31.67% | 71.75 | 8.36% | 2.65% | 733.00 | 775.00 | 1.40% | $ 97.40 | $ 82.50 | $ 89.95 | 61.75 | 1.46 | 2.04% | 31.35% | 0.64% | 3.29% | 2.75% | 3.02% | 4.40% | -1.39% |
| Edison International | EIX | 5.25 | 2.90 | 44.76% | 47.75 | 10.99% | 4.92% | 365.00 | 385.00 | 1.34% | $ 76.40 | $ 53.40 | $ 64.90 | 37.90 | 1.71 | 2.30% | 41.60% | 0.96% | 5.88% | 6.68% | 6.28% | 3.08% | 3.20% |
| Entergy Corp. | ETR | 6.75 | 4.30 | 36.30% | 63.00 | 10.71% | 3.89% | 199.15 | 212.00 | 1.58% | $ 122.10 | $ 83.20 | $ 102.65 | 51.34 | 2.00 | 3.15% | 49.99% | 1.57% | 5.46% | 6.72% | 6.09% | 1.74% | 4.35% |
| Eversource Energy | ES | 4.50 | 2.85 | 36.67% | 48.50 | 9.28% | 3.40% | 324.00 | 355.00 | 2.31% | $ 86.60 | $ 63.10 | $ 74.85 | 37.70 | 1.99 | 4.59% | 49.63% | 2.28% | 5.68% | 5.75% | 5.72% | 6.87% | -1.15% |
| Hawaiian Electric Industries, Inc. | HE | 2.25 | 1.50 | 33.33% | 24.00 | 9.38% | 3.13% | 109.00 | 113.00 | 0.91% | $ 47.60 | $ 35.10 | $ 41.35 | 20.45 | 2.02 | 1.83% | 50.54% | 0.92% | 4.05% | 3.96% | 4.00% | 4.32% | -0.31% |
| IDACORP Inc. | IDA | 5.25 | 3.35 | 36.19% | 56.25 | 9.33% | 3.38% | 50.40 | 50.40 | 0.00% | $ 114.00 | $ 89.30 | $ 101.65 | 48.85 | 2.08 | 0.00% | 51.94% | 0.00% | 3.38% | 3.87% | 3.62% | 4.22% | -0.60% |
| MGE Energy Inc | MGEE | 3.25 | 1.70 | 47.69% | 31.25 | 10.40% | 4.96% | 34.67 | 34.67 | 0.00% | $ 80.80 | $ 56.70 | $ 68.75 | 24.68 | 2.79 | 0.00% | 64.10% | 0.00% | 4.96% | 4.58% | 4.77% | 6.67% | -1.90% |
| NextEra Energy, Inc. | NEE | 12.50 | 8.00 | 36.00% | 97.50 | 12.82% | 4.62% | 489.00 | 495.00 | 0.31% | $ 245.00 | $ 168.70 | $ 206.85 | 75.65 | 2.73 | 0.83% | 63.43% | 0.53% | 5.14% | 4.18% | 4.66% | 12.66% | -8.00% |
| NorthWestern Corporation | NWE | 3.75 | 2.70 | 28.00% | 44.50 | 8.43% | 2.36% | 50.50 | 51.60 | 0.54% | $ 76.70 | $ 57.30 | $ 67.00 | 40.20 | 1.67 | 0.90% | 40.00% | 0.36% | 2.72% | 3.47% | 3.09% | 1.38% | 1.71% |
| OGE Energy Corp. | OGE | 2.75 | 1.85 | 32.73% | 24.25 | 11.34% | 3.71% | 200.10 | 200.00 | -0.01% | $ 45.80 | $ 38.00 | $ 41.90 | 20.69 | 2.03 | -0.03% | 50.62% | -0.01% | 3.70% | 3.52% | 3.61% | 5.26% | -1.65% |
| Otter Tail Corporation | OTTR | 2.50 | 1.65 | 34.00% | 24.50 | 10.20% | 3.47% | 40.16 | 41.50 | 0.82% | $ 57.70 | $ 45.90 | $ 51.80 | 19.46 | 2.66 | 2.19% | 62.43% | 1.37% | 4.84% | 5.33% | 5.08% | 3.60% | 1.48% |
| Pinnacle West Capital Corporation | PNW | 5.50 | 3.80 | 30.91% | 54.75 | 10.05% | 3.11% | 113.00 | 118.00 | 1.09% | $ 99.80 | $ 81.60 | $ 90.70 | 47.70 | 1.90 | 2.07% | 47.41% | 0.98% | 4.09% | 4.04% | 4.06% | 5.14% | -1.08% |
| PNM Resources, Inc. | PNM | 2.50 | 1.50 | 40.00% | 28.00 | 8.93% | 3.57% | 79.65 | 90.00 | 3.10% | $ 53.00 | $ 39.70 | $ 46.35 | 20.80 | 2.23 | 6.91% | 55.12% | 3.81% | 7.38% | 8.71% | 8.05% | 3.25% | 4.80% |
| Portland General Electric Company | POR | 3.00 | 1.95 | 35.00% | 32.75 | 9.16% | 3.21% | 89.40 | 90.00 | 0.17% | $ 58.40 | $ 44.00 | $ 51.20 | 28.90 | 1.77 | 0.30% | 43.55% | 0.13% | 3.34% | 3.17% | 3.25% | 5.74% | -2.48% |
| Public Service Enterprie Group, Inc. | PEG | 4.25 | 2.40 | 43.53% | 38.00 | 11.18% | 4.87% | 506.00 | 506.00 | 0.00% | $ 63.90 | $ 50.00 | $ 56.95 | 29.65 | 1.92 | 0.00% | 47.94% | 0.00% | 4.87% | 6.14% | 5.50% | 3.53% | 1.98% |
| SEMPRA Energy | SRE | 9.00 | 5.25 | 41.67% | 77.50 | 11.61% | 4.84% | 290.00 | 320.00 | 2.49% | $ 154.50 | $ 106.10 | $ 130.30 | 61.25 | 2.13 | 5.30% | 52.99% | 2.81% | 7.65% | 6.04% | 6.84% | 11.37% | -4.53% |
| Southern Company | SO | 4.00 | 2.86 | 28.50% | 31.50 | 12.70% | 3.62% | 1050.00 | 1080.00 | 0.71% | $ 64.30 | $ 43.30 | $ 53.80 | 26.20 | 2.05 | 1.45% | 51.30% | 0.74% | 4.36% | 3.19% | 3.78% | 6.58% | -2.80% |
| WEC Energy Group, Inc. | WEC | 4.50 | 3.00 | 33.33% | 38.25 | 11.76% | 3.92% | 315.50 | 315.50 | 0.00% | $ 98.20 | $ 67.20 | $ 82.70 | 32.06 | 2.58 | 0.00% | 61.23% | 0.00% | 3.92% | 3.81% | 3.86% | 5.88% | -2.02% |
| Xcel Energy Inc. | XEL | 3.25 | 2.05 | 36.92% | 31.00 | 10.48% | 3.87% | 525.00 | 546.00 | 0.99% | $ 66.10 | $ 47.70 | $ 56.90 | 25.15 | 2.26 | 2.23% | 55.80% | 1.24% | 5.11% | 5.14% | 5.13% | 5.74% | -0.61% |
| | | | Average: | 35.85% | | 10.35% | 0.0371 | | | | | | | | | | | Mean: | 4.90% | 4.63% | 4.77% | 6.37% | -1.60% |
| | | | | | | | | | | | | | | | | | | Median: | 4.85% | 4.38% | 4.72% | 5.50% | -0.85% |

Number of underestimates: 17
Number of overestimates: 9

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.25 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Source: Value Line
[14] Equals [12] / [13]
[15] Equals [9] x [14]
[16] Equals 1 - (1 / [14])
[17] Equals [15] x [16]
[18] Equals [6] + [17]
[19] Source: Rebuttal Exhibit DWD-22 SGR for 2019
[20] Equals Average ([18], [19])

Alternative Bond Yield Plus Risk Premium Analyses

| [1] | [2] | [3] | [4] |
|---|---|---|---|
| 30-Year Treasury Yield | Moody's Utility A Yield | Moody's Utility A Credit Spread | VIX |
| 1.37% | 3.52% | 2.15% | 55.27 |

| | Risk Premium | Return on Equity |
|---|---|---|
| Regression Result - Credit Spread, VIX | 9.61% | 10.98% |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.830664 |
| R Square | 0.690002 |
| Adjusted R Square | 0.688757 |
| Standard Error | 0.005294 |
| Observations | 751 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 3 | 0.046591617 | 0.01553054 | 554.2310236 | 1.911E-189 |
| Residual | 747 | 0.020932268 | 2.8022E-05 | | |
| Total | 750 | 0.067523885 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | -0.025834 | 0.002148908 | -12.021801 | 1.47195E-30 | -0.03005236 | -0.021615129 |
| LN(30-Year Treasury) | -0.025051 | 0.0006218 | -40.287632 | 1.809E-189 | -0.02627151 | -0.023830149 |
| Moody's Utility A Credit Spread | 0.197117 | 0.086327424 | 2.28336303 | 0.022688979 | 0.027643617 | 0.366590081 |
| VIX | 0.000185 | 5.44561E-05 | 3.39616011 | 0.000719527 | 7.80364E-05 | 0.000291847 |

Notes:
[1] Source: Bloomberg Professional, Rebuttal Exhibit DWD-5
[2] Source: Bloomberg Professional; 30-day average as of April 17, 2020
[3] Equals [2] - [1]
[4] Source: Bloomberg Professional; 30-day average as of April 17, 2020
[5] Source: S&P Global Market Intelligence
[6] Source: S&P Global Market Intelligence
[7] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[9] Equals LN[7]
[10] Equals [8] - [7]
[11] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[12] Equals [6] - [7]

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 11/2/1993 | 10.80% | 6.60% | 7.59% | -2.72 | 0.99% | 12.67 | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | 7.56% | -2.72 | 1.00% | 12.76 | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | 7.53% | -2.73 | 1.01% | 12.85 | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | 7.49% | -2.74 | 1.01% | 12.75 | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | 7.48% | -2.74 | 1.01% | 12.72 | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | 7.48% | -2.74 | 1.01% | 12.66 | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | 7.45% | -2.74 | 1.01% | 12.49 | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | 7.43% | -2.75 | 1.01% | 12.45 | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | 7.41% | -2.75 | 1.01% | 12.39 | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | 7.40% | -2.75 | 1.01% | 12.37 | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | 7.39% | -2.75 | 1.01% | 12.34 | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | 7.37% | -2.76 | 1.02% | 12.38 | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | 7.37% | -2.76 | 1.02% | 12.39 | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | 7.37% | -2.76 | 1.02% | 12.39 | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | 7.37% | -2.76 | 1.02% | 12.40 | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | 7.36% | -2.76 | 1.02% | 12.43 | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | 7.41% | -2.75 | 1.01% | 13.03 | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | 7.45% | -2.74 | 1.01% | 13.20 | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | 7.47% | -2.74 | 1.01% | 13.25 | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | 7.53% | -2.73 | 0.99% | 13.32 | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | 7.63% | -2.71 | 0.98% | 13.42 | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | 7.83% | -2.68 | 0.95% | 13.42 | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | 8.23% | -2.61 | 0.89% | 13.77 | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | 8.29% | -2.60 | 0.89% | 13.94 | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | 8.29% | -2.60 | 0.89% | 13.94 | 3.45% |
| 11/18/1994 | 11.20% | 7.46% | 8.34% | -2.60 | 0.88% | 14.12 | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | 8.35% | -2.59 | 0.88% | 14.14 | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | 8.38% | -2.59 | 0.88% | 14.20 | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | 8.43% | -2.58 | 0.88% | 14.29 | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | 8.43% | -2.58 | 0.88% | 14.29 | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | 8.45% | -2.58 | 0.89% | 14.28 | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | 8.46% | -2.58 | 0.89% | 14.26 | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | 8.47% | -2.58 | 0.89% | 14.24 | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | 8.50% | -2.58 | 0.88% | 14.14 | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | 8.53% | -2.57 | 0.89% | 14.14 | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | 8.58% | -2.57 | 0.89% | 13.71 | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | 8.60% | -2.56 | 0.89% | 13.56 | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | 8.60% | -2.56 | 0.90% | 13.49 | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | 8.61% | -2.56 | 0.90% | 13.37 | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | 8.61% | -2.56 | 0.89% | 13.35 | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | 8.61% | -2.56 | 0.89% | 13.32 | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | 8.62% | -2.56 | 0.90% | 13.31 | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | 8.62% | -2.56 | 0.90% | 13.30 | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | 8.62% | -2.56 | 0.90% | 13.28 | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | 8.61% | -2.56 | 0.91% | 13.20 | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | 8.58% | -2.57 | 0.90% | 13.21 | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | 8.56% | -2.57 | 0.91% | 13.22 | 3.55% |
| 6/9/1995 | 11.25% | 7.60% | 8.52% | -2.58 | 0.92% | 13.26 | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | 8.48% | -2.58 | 0.93% | 13.24 | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | 8.45% | -2.59 | 0.94% | 13.20 | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | 8.17% | -2.63 | 0.97% | 12.48 | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | 8.10% | -2.64 | 0.98% | 12.24 | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | 8.10% | -2.64 | 0.98% | 12.24 | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | 8.10% | -2.64 | 0.98% | 12.24 | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | 8.09% | -2.64 | 0.98% | 12.24 | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | 7.90% | -2.67 | 1.01% | 12.47 | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | 7.90% | -2.67 | 1.01% | 12.47 | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | 7.87% | -2.68 | 1.02% | 12.51 | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | 7.82% | -2.69 | 1.04% | 12.52 | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | 7.79% | -2.70 | 1.05% | 12.52 | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | 7.74% | -2.70 | 1.05% | 12.50 | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | 7.72% | -2.71 | 1.06% | 12.48 | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | 7.58% | -2.74 | 1.11% | 12.63 | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | 7.52% | -2.75 | 1.11% | 13.49 | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | 7.53% | -2.75 | 1.11% | 13.63 | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | 7.53% | -2.74 | 1.11% | 13.74 | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | 7.53% | -2.74 | 1.11% | 13.74 | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | 7.55% | -2.74 | 1.12% | 13.93 | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | 7.55% | -2.74 | 1.12% | 13.99 | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | 7.57% | -2.74 | 1.13% | 14.15 | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | 7.57% | -2.74 | 1.14% | 14.24 | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | 7.60% | -2.74 | 1.12% | 14.73 | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | 7.60% | -2.74 | 1.12% | 14.77 | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | 7.67% | -2.72 | 1.10% | 15.35 | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | 7.76% | -2.70 | 1.05% | 15.98 | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | 7.80% | -2.69 | 1.03% | 16.22 | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | 7.83% | -2.69 | 1.02% | 16.44 | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | 7.85% | -2.68 | 1.01% | 16.58 | 4.47% |
| 12/18/1996 | 11.75% | 6.84% | 7.85% | -2.68 | 1.02% | 16.80 | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | 7.85% | -2.68 | 1.02% | 16.84 | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | 7.85% | -2.68 | 1.02% | 16.85 | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | 7.83% | -2.68 | 1.01% | 17.23 | 4.98% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 2/20/1997 | 11.80% | 6.82% | 7.82% | -2.69 | 1.01% | 17.29 | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | 7.80% | -2.69 | 1.00% | 17.83 | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | 7.80% | -2.69 | 1.00% | 17.86 | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | 7.80% | -2.69 | 0.99% | 18.20 | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | 7.80% | -2.69 | 0.99% | 18.20 | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | 7.75% | -2.69 | 0.97% | 19.04 | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | 7.60% | -2.72 | 1.00% | 22.58 | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | 7.54% | -2.72 | 0.97% | 22.85 | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | 7.47% | -2.75 | 1.08% | 23.45 | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | 7.39% | -2.77 | 1.10% | 23.41 | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | 7.38% | -2.77 | 1.11% | 23.39 | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | 7.34% | -2.78 | 1.12% | 23.36 | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | 7.26% | -2.79 | 1.14% | 23.68 | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | 7.16% | -2.82 | 1.23% | 23.14 | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | 7.09% | -2.85 | 1.31% | 23.80 | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | 7.05% | -2.89 | 1.47% | 26.06 | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | 7.05% | -2.89 | 1.51% | 26.34 | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | 7.04% | -2.90 | 1.52% | 26.58 | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | 7.01% | -2.92 | 1.63% | 27.54 | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | 7.01% | -2.93 | 1.67% | 28.19 | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | 7.03% | -2.93 | 1.71% | 28.47 | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | 7.25% | -2.90 | 1.74% | 25.77 | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | 7.43% | -2.86 | 1.73% | 24.95 | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | 7.63% | -2.83 | 1.73% | 24.31 | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | 7.80% | -2.81 | 1.75% | 23.49 | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | 7.80% | -2.81 | 1.75% | 23.49 | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | 7.95% | -2.78 | 1.77% | 23.35 | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | 8.04% | -2.78 | 1.85% | 22.96 | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | 8.19% | -2.78 | 2.00% | 23.84 | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | 8.27% | -2.79 | 2.11% | 23.36 | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | 8.31% | -2.81 | 2.28% | 22.44 | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | 8.28% | -2.83 | 2.40% | 22.97 | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | 8.28% | -2.83 | 2.40% | 23.03 | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | 8.20% | -2.85 | 2.41% | 23.49 | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | 8.18% | -2.85 | 2.41% | 23.15 | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | 7.97% | -2.88 | 2.35% | 24.39 | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | 7.93% | -2.88 | 2.31% | 24.93 | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | 7.89% | -2.88 | 2.29% | 25.07 | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | 7.89% | -2.88 | 2.29% | 25.07 | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | 7.88% | -2.88 | 2.29% | 24.96 | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | 7.82% | -2.89 | 2.26% | 24.49 | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | 7.80% | -2.89 | 2.25% | 24.53 | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | 7.80% | -2.89 | 2.25% | 24.55 | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | 7.79% | -2.89 | 2.24% | 24.84 | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | 7.77% | -2.89 | 2.23% | 25.69 | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | 7.75% | -2.90 | 2.26% | 26.17 | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | 7.75% | -2.90 | 2.26% | 26.22 | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | 7.76% | -2.90 | 2.26% | 26.14 | 7.00% |
| 1/22/2002 | 10.00% | 5.50% | 7.76% | -2.90 | 2.27% | 25.49 | 4.50% |
| 3/27/2002 | 10.10% | 5.45% | 7.69% | -2.91 | 2.24% | 24.65 | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | 7.67% | -2.91 | 2.22% | 24.49 | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | 7.64% | -2.91 | 2.17% | 24.29 | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | 7.63% | -2.91 | 2.16% | 24.33 | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | 7.62% | -2.90 | 2.15% | 24.42 | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | 7.62% | -2.90 | 2.15% | 24.46 | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | 7.62% | -2.90 | 2.15% | 24.46 | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | 7.60% | -2.90 | 2.13% | 24.08 | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | 7.51% | -2.91 | 2.06% | 25.15 | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | 7.48% | -2.92 | 2.06% | 25.82 | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | 7.36% | -2.94 | 2.07% | 28.03 | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | 7.34% | -2.94 | 2.08% | 28.29 | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | 7.33% | -2.95 | 2.08% | 28.48 | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | 7.29% | -2.96 | 2.10% | 28.93 | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | 7.24% | -2.97 | 2.11% | 29.66 | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | 7.18% | -2.99 | 2.14% | 30.74 | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | 7.17% | -2.99 | 2.14% | 30.99 | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | 7.16% | -2.99 | 2.14% | 31.04 | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | 7.13% | -3.00 | 2.15% | 31.54 | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | 7.10% | -3.00 | 2.14% | 31.74 | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | 7.07% | -3.01 | 2.13% | 31.70 | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | 6.85% | -3.04 | 2.05% | 28.27 | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | 6.84% | -3.04 | 2.05% | 28.19 | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | 6.82% | -3.04 | 2.03% | 27.44 | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | 6.80% | -3.04 | 2.01% | 26.97 | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | 6.79% | -3.04 | 1.99% | 26.27 | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | 6.73% | -3.03 | 1.90% | 24.78 | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | 6.51% | -3.01 | 1.57% | 20.47 | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | 6.51% | -3.01 | 1.57% | 20.47 | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | 6.50% | -3.01 | 1.57% | 20.40 | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | 6.50% | -3.01 | 1.56% | 20.31 | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | 6.50% | -3.01 | 1.56% | 20.31 | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | 6.50% | -3.01 | 1.56% | 20.15 | 5.56% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 1/13/2004 | 12.00% | 4.95% | 6.46% | -3.01 | 1.51% | 19.31 | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | 6.38% | -3.00 | 1.39% | 18.17 | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | 6.35% | -2.99 | 1.33% | 17.96 | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | 6.35% | -2.99 | 1.32% | 17.85 | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | 6.36% | -2.98 | 1.28% | 17.43 | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | 6.35% | -2.98 | 1.28% | 17.36 | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | 6.35% | -2.98 | 1.27% | 17.33 | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | 6.35% | -2.98 | 1.27% | 17.30 | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | 6.32% | -2.98 | 1.22% | 16.96 | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | 6.32% | -2.98 | 1.22% | 16.96 | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | 6.30% | -2.97 | 1.19% | 16.69 | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | 6.27% | -2.98 | 1.17% | 16.53 | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | 6.25% | -2.98 | 1.16% | 16.35 | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | 6.20% | -2.98 | 1.13% | 15.94 | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | 6.19% | -2.98 | 1.13% | 15.75 | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | 6.18% | -2.98 | 1.11% | 15.59 | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | 6.17% | -2.98 | 1.10% | 15.51 | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | 6.17% | -2.98 | 1.10% | 15.51 | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | 6.17% | -2.98 | 1.10% | 15.47 | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | 6.17% | -2.98 | 1.10% | 15.47 | 6.43% |
| 12/29/2004 | 9.85% | 5.08% | 6.17% | -2.98 | 1.10% | 15.30 | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | 6.17% | -2.98 | 1.09% | 15.12 | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | 6.08% | -3.00 | 1.11% | 14.59 | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | 6.06% | -3.00 | 1.11% | 14.46 | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | 6.02% | -3.01 | 1.10% | 14.18 | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | 5.99% | -3.02 | 1.09% | 14.05 | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | 5.97% | -3.02 | 1.09% | 14.02 | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | 5.96% | -3.02 | 1.09% | 14.00 | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | 5.85% | -3.04 | 1.07% | 13.89 | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | 5.84% | -3.04 | 1.07% | 13.75 | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | 5.83% | -3.04 | 1.07% | 13.71 | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | 5.82% | -3.05 | 1.07% | 13.64 | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | 5.72% | -3.07 | 1.08% | 13.17 | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | 5.70% | -3.07 | 1.07% | 12.94 | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | 5.68% | -3.08 | 1.07% | 12.84 | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | 5.61% | -3.09 | 1.07% | 12.77 | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | 5.60% | -3.09 | 1.07% | 12.78 | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | 5.63% | -3.09 | 1.08% | 12.97 | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | 5.63% | -3.09 | 1.08% | 12.96 | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | 5.63% | -3.09 | 1.09% | 12.91 | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | 5.63% | -3.09 | 1.09% | 12.91 | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | 5.63% | -3.09 | 1.09% | 12.90 | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | 5.63% | -3.09 | 1.09% | 12.90 | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | 5.63% | -3.09 | 1.09% | 12.87 | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | 5.63% | -3.09 | 1.09% | 12.87 | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | 5.62% | -3.09 | 1.09% | 12.82 | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | 5.62% | -3.10 | 1.10% | 12.72 | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | 5.65% | -3.09 | 1.12% | 12.39 | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | 5.75% | -3.08 | 1.14% | 12.34 | 5.58% |
| 4/26/2006 | 10.60% | 4.64% | 5.78% | -3.07 | 1.14% | 12.34 | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | 5.85% | -3.06 | 1.15% | 12.47 | 6.91% |
| 6/6/2006 | 10.00% | 4.75% | 5.90% | -3.05 | 1.16% | 12.72 | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | 5.98% | -3.04 | 1.18% | 13.07 | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | 6.01% | -3.03 | 1.18% | 13.12 | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | 6.05% | -3.02 | 1.19% | 13.29 | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | 6.06% | -3.02 | 1.20% | 13.29 | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | 6.06% | -3.02 | 1.20% | 13.27 | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | 6.10% | -3.02 | 1.21% | 13.20 | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | 6.10% | -3.02 | 1.21% | 13.19 | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | 6.11% | -3.01 | 1.21% | 13.25 | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | 6.12% | -3.01 | 1.20% | 13.30 | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | 6.15% | -3.01 | 1.19% | 13.12 | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | 6.15% | -3.01 | 1.19% | 13.12 | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | 6.15% | -3.01 | 1.19% | 13.12 | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | 6.14% | -3.00 | 1.19% | 13.07 | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | 6.14% | -3.00 | 1.19% | 13.07 | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | 6.14% | -3.00 | 1.19% | 13.06 | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | 6.14% | -3.00 | 1.18% | 12.98 | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | 6.14% | -3.00 | 1.18% | 12.98 | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | 6.14% | -3.00 | 1.18% | 12.98 | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | 6.13% | -3.01 | 1.18% | 12.97 | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | 6.13% | -3.01 | 1.19% | 12.96 | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | 6.03% | -3.02 | 1.16% | 12.81 | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | 6.03% | -3.02 | 1.16% | 12.78 | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | 5.94% | -3.04 | 1.13% | 12.22 | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | 5.94% | -3.04 | 1.13% | 12.21 | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | 5.94% | -3.04 | 1.13% | 12.21 | 5.45% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 5/22/2007 | 10.20% | 4.80% | 5.94% | -3.04 | 1.13% | 12.19 | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | 5.94% | -3.04 | 1.13% | 12.19 | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | 5.94% | -3.04 | 1.13% | 12.18 | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | 5.93% | -3.04 | 1.13% | 12.16 | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | 5.94% | -3.03 | 1.12% | 12.27 | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | 5.94% | -3.03 | 1.12% | 12.30 | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | 5.94% | -3.03 | 1.12% | 12.31 | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | 5.95% | -3.03 | 1.11% | 12.38 | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | 5.96% | -3.02 | 1.11% | 12.56 | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | 5.97% | -3.02 | 1.11% | 12.65 | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | 5.97% | -3.02 | 1.11% | 12.65 | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | 5.99% | -3.02 | 1.12% | 13.76 | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | 6.07% | -3.01 | 1.16% | 15.94 | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | 6.08% | -3.01 | 1.17% | 16.15 | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | 6.09% | -3.02 | 1.18% | 16.62 | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | 6.08% | -3.02 | 1.21% | 18.14 | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | 6.09% | -3.02 | 1.22% | 18.45 | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | 6.10% | -3.02 | 1.24% | 18.60 | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | 6.10% | -3.02 | 1.24% | 18.62 | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | 6.10% | -3.02 | 1.24% | 18.62 | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | 6.11% | -3.02 | 1.25% | 18.74 | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | 6.11% | -3.03 | 1.25% | 18.77 | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | 6.11% | -3.03 | 1.25% | 18.77 | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | 6.12% | -3.03 | 1.27% | 18.84 | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | 6.12% | -3.03 | 1.27% | 18.88 | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | 6.12% | -3.03 | 1.29% | 19.16 | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | 6.12% | -3.03 | 1.31% | 19.51 | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | 6.12% | -3.04 | 1.33% | 19.99 | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | 6.12% | -3.04 | 1.33% | 20.14 | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | 6.12% | -3.04 | 1.34% | 20.21 | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | 6.15% | -3.05 | 1.41% | 21.45 | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | 6.16% | -3.05 | 1.44% | 21.99 | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | 6.16% | -3.06 | 1.48% | 22.55 | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | 6.16% | -3.08 | 1.56% | 23.32 | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | 6.16% | -3.08 | 1.56% | 23.35 | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | 6.16% | -3.08 | 1.57% | 23.46 | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | 6.16% | -3.09 | 1.60% | 23.32 | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | 6.16% | -3.09 | 1.61% | 23.18 | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | 6.17% | -3.09 | 1.62% | 22.89 | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | 6.18% | -3.09 | 1.65% | 22.73 | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | 6.18% | -3.09 | 1.65% | 22.73 | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | 6.19% | -3.10 | 1.66% | 22.88 | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | 6.19% | -3.10 | 1.67% | 23.08 | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | 6.20% | -3.10 | 1.69% | 23.33 | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | 6.20% | -3.10 | 1.70% | 23.34 | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | 6.22% | -3.10 | 1.71% | 23.37 | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | 6.24% | -3.10 | 1.74% | 23.23 | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | 6.25% | -3.10 | 1.75% | 23.01 | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | 6.28% | -3.11 | 1.79% | 23.46 | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.28% | -3.11 | 1.79% | 23.46 | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.28% | -3.11 | 1.79% | 23.46 | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | 6.29% | -3.11 | 1.82% | 23.77 | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | 6.31% | -3.11 | 1.85% | 24.61 | 5.69% |
| 11/13/2008 | 10.55% | 4.45% | 6.52% | -3.11 | 2.08% | 29.58 | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | 6.54% | -3.11 | 2.10% | 29.98 | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | 6.59% | -3.12 | 2.20% | 31.79 | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | 6.62% | -3.15 | 2.35% | 34.13 | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | 6.62% | -3.16 | 2.38% | 34.34 | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | 6.62% | -3.16 | 2.38% | 34.34 | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | 6.62% | -3.17 | 2.40% | 34.47 | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | 6.63% | -3.18 | 2.48% | 35.25 | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | 6.63% | -3.19 | 2.51% | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.63% | -3.19 | 2.51% | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.63% | -3.19 | 2.51% | 35.81 | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | 6.63% | -3.20 | 2.54% | 36.26 | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | 6.64% | -3.20 | 2.56% | 36.58 | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | 6.64% | -3.20 | 2.58% | 36.94 | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | 6.64% | -3.23 | 2.68% | 39.59 | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | 6.64% | -3.24 | 2.71% | 40.42 | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | 6.65% | -3.26 | 2.80% | 42.04 | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | 6.66% | -3.27 | 2.86% | 42.91 | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | 6.66% | -3.27 | 2.87% | 43.10 | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | 6.66% | -3.28 | 2.89% | 43.29 | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | 6.67% | -3.28 | 2.90% | 43.40 | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | 6.66% | -3.29 | 2.92% | 43.96 | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | 6.67% | -3.29 | 2.93% | 44.24 | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | 6.66% | -3.28 | 2.90% | 45.01 | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | 6.66% | -3.28 | 2.90% | 45.06 | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | 6.65% | -3.28 | 2.88% | 44.95 | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | 6.62% | -3.28 | 2.84% | 44.55 | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | 6.33% | -3.27 | 2.51% | 38.96 | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | 6.13% | -3.21 | 2.11% | 33.90 | 6.68% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 10/23/2009 | 10.88% | 4.06% | 6.10% | -3.20 | 2.04% | 33.22 | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | 6.08% | -3.20 | 1.99% | 32.57 | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | 6.08% | -3.19 | 1.98% | 32.48 | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | 6.02% | -3.18 | 1.87% | 30.89 | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | 6.02% | -3.18 | 1.86% | 30.79 | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | 6.02% | -3.18 | 1.85% | 30.58 | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | 6.01% | -3.18 | 1.83% | 30.18 | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | 6.00% | -3.17 | 1.81% | 29.90 | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | 5.98% | -3.17 | 1.76% | 28.98 | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | 5.98% | -3.17 | 1.76% | 28.98 | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | 5.98% | -3.16 | 1.75% | 28.70 | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | 5.98% | -3.16 | 1.75% | 28.70 | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | 5.97% | -3.16 | 1.74% | 28.46 | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | 5.97% | -3.16 | 1.74% | 28.46 | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | 5.97% | -3.16 | 1.74% | 28.46 | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | 5.96% | -3.16 | 1.69% | 27.91 | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | 5.95% | -3.15 | 1.67% | 27.67 | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | 5.94% | -3.15 | 1.63% | 27.09 | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | 5.90% | -3.13 | 1.55% | 26.08 | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | 5.90% | -3.13 | 1.54% | 26.01 | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | 5.90% | -3.13 | 1.54% | 26.01 | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | 5.90% | -3.13 | 1.54% | 26.01 | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | 5.86% | -3.13 | 1.48% | 25.43 | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | 5.85% | -3.12 | 1.45% | 25.05 | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | 5.83% | -3.12 | 1.43% | 24.80 | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | 5.82% | -3.12 | 1.41% | 24.54 | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | 5.82% | -3.12 | 1.40% | 24.43 | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | 5.81% | -3.12 | 1.40% | 24.37 | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | 5.80% | -3.12 | 1.39% | 24.10 | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | 5.79% | -3.12 | 1.37% | 23.85 | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | 5.77% | -3.12 | 1.35% | 23.47 | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | 5.76% | -3.12 | 1.33% | 22.82 | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | 5.74% | -3.11 | 1.29% | 22.16 | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | 5.74% | -3.11 | 1.28% | 22.11 | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | 5.74% | -3.11 | 1.28% | 22.11 | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | 5.74% | -3.11 | 1.28% | 22.11 | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | 5.72% | -3.11 | 1.26% | 22.26 | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | 5.72% | -3.11 | 1.26% | 22.26 | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | 5.70% | -3.11 | 1.25% | 22.81 | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | 5.70% | -3.11 | 1.25% | 22.81 | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | 5.69% | -3.11 | 1.25% | 23.00 | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | 5.69% | -3.11 | 1.25% | 23.16 | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | 5.68% | -3.12 | 1.25% | 23.19 | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | 5.68% | -3.12 | 1.25% | 23.19 | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | 5.68% | -3.12 | 1.25% | 23.30 | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | 5.68% | -3.12 | 1.25% | 23.34 | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | 5.67% | -3.12 | 1.24% | 23.43 | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | 5.67% | -3.12 | 1.24% | 23.43 | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | 5.66% | -3.12 | 1.24% | 23.39 | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | 5.65% | -3.12 | 1.24% | 23.40 | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | 5.65% | -3.12 | 1.24% | 23.41 | 5.42% |
| 8/25/2010 | 9.90% | 4.37% | 5.60% | -3.13 | 1.23% | 23.38 | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | 5.58% | -3.14 | 1.23% | 23.44 | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | 5.56% | -3.14 | 1.23% | 23.46 | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | 5.56% | -3.14 | 1.23% | 23.44 | 5.68% |
| 9/16/2010 | 10.00% | 4.32% | 5.56% | -3.14 | 1.23% | 23.44 | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | 5.52% | -3.15 | 1.23% | 23.47 | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | 5.48% | -3.16 | 1.24% | 23.50 | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | 5.45% | -3.17 | 1.24% | 23.55 | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | 5.44% | -3.17 | 1.24% | 23.60 | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | 5.43% | -3.17 | 1.24% | 23.54 | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | 5.42% | -3.18 | 1.24% | 23.28 | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | 5.41% | -3.18 | 1.24% | 23.24 | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | 5.40% | -3.18 | 1.24% | 23.21 | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | 5.39% | -3.18 | 1.24% | 23.18 | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | 5.38% | -3.18 | 1.24% | 23.14 | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | 5.38% | -3.18 | 1.24% | 23.13 | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | 5.38% | -3.18 | 1.24% | 23.12 | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | 5.38% | -3.18 | 1.24% | 23.12 | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | 5.38% | -3.18 | 1.23% | 23.11 | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | 5.38% | -3.18 | 1.23% | 23.10 | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | 5.38% | -3.18 | 1.23% | 23.09 | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | 5.37% | -3.18 | 1.23% | 23.07 | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | 5.37% | -3.19 | 1.23% | 23.07 | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | 5.36% | -3.19 | 1.23% | 23.08 | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | 5.35% | -3.19 | 1.23% | 23.07 | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | 5.35% | -3.19 | 1.23% | 23.06 | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | 5.35% | -3.19 | 1.23% | 23.05 | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | 5.34% | -3.19 | 1.23% | 23.06 | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | 5.34% | -3.19 | 1.23% | 23.06 | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | 5.33% | -3.19 | 1.22% | 23.12 | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | 5.33% | -3.19 | 1.22% | 23.13 | 5.89% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 2/25/2011 | 10.00% | 4.14% | 5.34% | -3.18 | 1.20% | 22.58 | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | 5.34% | -3.18 | 1.17% | 21.29 | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | 5.35% | -3.17 | 1.16% | 21.16 | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | 5.35% | -3.17 | 1.14% | 20.69 | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | 5.37% | -3.16 | 1.13% | 20.17 | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | 5.37% | -3.16 | 1.13% | 20.13 | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | 5.37% | -3.16 | 1.13% | 20.08 | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | 5.37% | -3.16 | 1.13% | 19.84 | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | 5.37% | -3.16 | 1.13% | 19.84 | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | 5.38% | -3.15 | 1.11% | 19.44 | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | 5.39% | -3.15 | 1.09% | 19.02 | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | 5.40% | -3.14 | 1.09% | 18.83 | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | 5.40% | -3.14 | 1.09% | 18.83 | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | 5.43% | -3.13 | 1.06% | 18.48 | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | 5.44% | -3.13 | 1.05% | 18.46 | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | 5.43% | -3.13 | 1.05% | 18.77 | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | 5.42% | -3.13 | 1.05% | 19.05 | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | 5.42% | -3.13 | 1.05% | 19.13 | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | 5.41% | -3.13 | 1.05% | 19.53 | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | 5.37% | -3.14 | 1.05% | 20.31 | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | 5.31% | -3.16 | 1.07% | 21.34 | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | 5.23% | -3.19 | 1.09% | 22.82 | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | 5.20% | -3.19 | 1.10% | 23.27 | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | 5.02% | -3.25 | 1.15% | 25.28 | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | 5.02% | -3.25 | 1.15% | 25.28 | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | 4.96% | -3.27 | 1.17% | 25.67 | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | 4.96% | -3.27 | 1.17% | 25.67 | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | 4.93% | -3.28 | 1.17% | 25.76 | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | 4.93% | -3.28 | 1.17% | 25.76 | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | 4.92% | -3.28 | 1.17% | 25.77 | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | 4.92% | -3.28 | 1.17% | 25.77 | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | 4.92% | -3.29 | 1.18% | 25.76 | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | 4.79% | -3.33 | 1.23% | 25.89 | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | 4.78% | -3.34 | 1.23% | 25.91 | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | 4.70% | -3.36 | 1.23% | 26.12 | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | 4.68% | -3.37 | 1.24% | 26.14 | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | 4.67% | -3.37 | 1.25% | 26.15 | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | 4.66% | -3.38 | 1.25% | 26.16 | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | 4.57% | -3.41 | 1.26% | 25.99 | 7.06% |
| 4/4/2012 | 10.00% | 3.29% | 4.56% | -3.41 | 1.27% | 25.89 | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | 4.48% | -3.44 | 1.28% | 25.91 | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | 4.47% | -3.45 | 1.29% | 25.85 | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | 4.45% | -3.45 | 1.29% | 25.85 | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | 4.42% | -3.46 | 1.28% | 25.79 | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | 4.40% | -3.47 | 1.29% | 25.23 | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | 4.38% | -3.48 | 1.30% | 24.77 | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | 4.36% | -3.49 | 1.30% | 24.45 | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | 4.36% | -3.49 | 1.30% | 24.40 | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | 4.36% | -3.49 | 1.30% | 24.33 | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | 4.35% | -3.49 | 1.30% | 24.25 | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | 4.34% | -3.49 | 1.30% | 23.82 | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | 4.34% | -3.49 | 1.30% | 23.58 | 6.96% |
| 7/9/2012 | 10.20% | 3.03% | 4.32% | -3.50 | 1.30% | 23.14 | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | 4.31% | -3.50 | 1.29% | 22.59 | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | 4.30% | -3.50 | 1.30% | 22.07 | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | 4.30% | -3.50 | 1.30% | 22.07 | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | 4.22% | -3.53 | 1.28% | 19.11 | 6.86% |
| 9/19/2012 | 9.80% | 2.94% | 4.22% | -3.53 | 1.28% | 18.84 | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | 4.22% | -3.53 | 1.28% | 18.84 | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | 4.21% | -3.53 | 1.27% | 18.51 | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | 4.19% | -3.53 | 1.26% | 18.04 | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | 4.17% | -3.53 | 1.24% | 17.84 | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | 4.17% | -3.53 | 1.24% | 17.83 | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | 4.14% | -3.53 | 1.22% | 17.75 | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | 4.11% | -3.54 | 1.22% | 17.60 | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | 4.11% | -3.54 | 1.22% | 17.58 | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | 4.11% | -3.54 | 1.22% | 17.58 | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | 4.10% | -3.54 | 1.21% | 17.53 | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | 4.10% | -3.54 | 1.21% | 17.53 | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | 4.09% | -3.55 | 1.21% | 17.48 | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | 4.09% | -3.55 | 1.21% | 17.47 | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | 4.09% | -3.55 | 1.21% | 17.47 | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | 4.09% | -3.55 | 1.21% | 17.47 | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | 4.09% | -3.55 | 1.22% | 17.44 | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | 4.09% | -3.55 | 1.22% | 17.44 | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.58% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 12/21/2012 | 10.20% | 2.87% | 4.08% | -3.55 | 1.22% | 17.43 | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | 4.08% | -3.55 | 1.22% | 17.45 | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | 4.06% | -3.56 | 1.22% | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 4.06% | -3.56 | 1.22% | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 4.06% | -3.56 | 1.22% | 17.50 | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | 4.05% | -3.56 | 1.21% | 17.45 | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | 4.05% | -3.56 | 1.21% | 17.45 | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | 4.03% | -3.56 | 1.18% | 17.01 | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | 4.02% | -3.56 | 1.17% | 16.89 | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | 4.02% | -3.56 | 1.16% | 16.85 | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | 4.02% | -3.55 | 1.14% | 16.34 | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | 4.03% | -3.54 | 1.13% | 15.87 | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | 4.02% | -3.53 | 1.08% | 15.25 | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | 4.03% | -3.52 | 1.07% | 15.02 | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | 4.05% | -3.51 | 1.07% | 14.87 | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | 4.05% | -3.51 | 1.07% | 14.89 | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | 4.06% | -3.51 | 1.06% | 14.95 | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | 4.08% | -3.50 | 1.06% | 14.99 | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | 4.09% | -3.50 | 1.06% | 15.02 | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | 4.13% | -3.48 | 1.06% | 15.06 | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | 4.20% | -3.46 | 1.05% | 14.82 | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | 4.22% | -3.45 | 1.05% | 14.72 | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | 4.31% | -3.42 | 1.04% | 14.56 | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | 4.31% | -3.42 | 1.04% | 14.56 | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | 4.35% | -3.41 | 1.04% | 14.46 | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | 4.38% | -3.40 | 1.04% | 14.45 | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | 4.44% | -3.38 | 1.04% | 14.40 | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | 4.47% | -3.37 | 1.03% | 14.36 | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | 4.48% | -3.37 | 1.03% | 14.36 | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | 4.49% | -3.36 | 1.02% | 14.38 | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | 4.50% | -3.36 | 1.02% | 14.38 | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | 4.50% | -3.36 | 1.02% | 14.38 | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | 4.51% | -3.36 | 1.02% | 14.34 | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | 4.51% | -3.36 | 1.02% | 14.34 | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | 4.52% | -3.35 | 1.02% | 14.34 | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | 4.52% | -3.35 | 1.02% | 14.35 | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | 4.52% | -3.35 | 1.02% | 14.35 | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | 4.52% | -3.35 | 1.02% | 14.35 | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | 4.53% | -3.35 | 1.02% | 14.38 | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | 4.55% | -3.34 | 1.01% | 14.41 | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | 4.65% | -3.30 | 0.96% | 14.62 | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | 4.66% | -3.30 | 0.96% | 14.65 | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | 4.68% | -3.29 | 0.96% | 14.72 | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | 4.68% | -3.29 | 0.95% | 14.66 | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | 4.68% | -3.29 | 0.95% | 14.66 | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | 4.68% | -3.29 | 0.95% | 14.58 | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | 4.63% | -3.30 | 0.93% | 14.38 | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | 4.61% | -3.30 | 0.93% | 14.35 | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | 4.60% | -3.30 | 0.93% | 14.26 | 6.73% |
| 6/30/2014 | 9.55% | 3.64% | 4.56% | -3.31 | 0.92% | 13.95 | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | 4.55% | -3.31 | 0.92% | 13.91 | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | 4.54% | -3.32 | 0.91% | 13.86 | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | 4.52% | -3.32 | 0.91% | 13.68 | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | 4.50% | -3.32 | 0.90% | 13.57 | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | 4.50% | -3.32 | 0.90% | 13.55 | 6.30% |
| 8/20/2014 | 9.75% | 3.56% | 4.46% | -3.33 | 0.90% | 13.61 | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | 4.45% | -3.34 | 0.90% | 13.59 | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | 4.44% | -3.34 | 0.90% | 13.57 | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | 4.42% | -3.35 | 0.90% | 13.57 | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | 4.41% | -3.35 | 0.91% | 13.57 | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | 4.36% | -3.37 | 0.91% | 13.62 | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | 4.29% | -3.39 | 0.92% | 14.09 | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | 4.29% | -3.39 | 0.92% | 14.09 | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | 4.28% | -3.40 | 0.93% | 13.94 | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | 4.26% | -3.40 | 0.94% | 13.82 | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | 4.26% | -3.40 | 0.94% | 13.82 | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | 4.25% | -3.41 | 0.95% | 13.78 | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | 4.24% | -3.41 | 0.95% | 13.80 | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | 4.24% | -3.41 | 0.95% | 13.80 | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | 4.24% | -3.42 | 0.95% | 13.83 | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | 4.23% | -3.42 | 0.95% | 13.86 | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | 4.22% | -3.42 | 0.96% | 13.96 | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | 4.22% | -3.42 | 0.96% | 13.98 | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | 4.13% | -3.46 | 0.99% | 14.37 | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | 4.05% | -3.49 | 1.02% | 14.67 | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | 4.02% | -3.51 | 1.04% | 14.90 | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | 4.00% | -3.52 | 1.04% | 14.96 | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | 4.00% | -3.52 | 1.05% | 14.98 | 6.77% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 4/23/2015 | 10.20% | 2.87% | 3.94% | -3.55 | 1.07% | 15.21 | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | 3.93% | -3.56 | 1.07% | 15.22 | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | 3.93% | -3.56 | 1.08% | 15.23 | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | 3.93% | -3.57 | 1.10% | 15.16 | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | 3.94% | -3.57 | 1.13% | 15.30 | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | 3.94% | -3.57 | 1.13% | 15.30 | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | 4.00% | -3.58 | 1.21% | 15.68 | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | 4.01% | -3.58 | 1.22% | 15.99 | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | 4.06% | -3.57 | 1.24% | 16.66 | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | 4.15% | -3.55 | 1.27% | 16.28 | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | 4.15% | -3.55 | 1.27% | 16.28 | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | 4.18% | -3.54 | 1.28% | 16.28 | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | 4.19% | -3.54 | 1.29% | 16.33 | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | 4.19% | -3.54 | 1.29% | 16.33 | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | 4.20% | -3.54 | 1.30% | 16.42 | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | 4.21% | -3.54 | 1.30% | 16.50 | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | 4.21% | -3.54 | 1.30% | 16.54 | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | 4.21% | -3.54 | 1.30% | 16.57 | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | 4.23% | -3.53 | 1.31% | 16.60 | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | 4.25% | -3.53 | 1.31% | 16.72 | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | 4.31% | -3.53 | 1.38% | 18.32 | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | 4.31% | -3.54 | 1.40% | 18.69 | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | 4.25% | -3.56 | 1.42% | 18.60 | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | 4.21% | -3.57 | 1.40% | 18.79 | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | 4.20% | -3.58 | 1.40% | 18.56 | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | 4.19% | -3.58 | 1.40% | 18.29 | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | 4.19% | -3.58 | 1.40% | 18.29 | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | 4.11% | -3.61 | 1.40% | 17.45 | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | 4.05% | -3.63 | 1.39% | 17.07 | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | 4.03% | -3.64 | 1.40% | 16.97 | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | 4.01% | -3.64 | 1.39% | 16.91 | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | 3.98% | -3.65 | 1.39% | 16.78 | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | 3.97% | -3.66 | 1.39% | 16.69 | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | 3.92% | -3.68 | 1.39% | 16.51 | 7.05% |
| 9/30/2016 | 9.90% | 2.53% | 3.91% | -3.68 | 1.38% | 16.46 | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | 3.84% | -3.70 | 1.36% | 15.63 | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | 3.84% | -3.70 | 1.36% | 15.60 | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | 3.84% | -3.69 | 1.35% | 15.49 | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | 3.84% | -3.69 | 1.35% | 15.34 | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | 3.85% | -3.69 | 1.34% | 14.95 | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | 3.85% | -3.68 | 1.34% | 14.87 | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | 3.85% | -3.68 | 1.33% | 14.76 | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | 3.85% | -3.68 | 1.33% | 14.76 | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | 3.85% | -3.68 | 1.33% | 14.72 | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | 3.85% | -3.68 | 1.33% | 14.62 | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | 3.86% | -3.68 | 1.32% | 14.58 | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | 3.86% | -3.67 | 1.32% | 14.50 | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | 3.86% | -3.67 | 1.32% | 14.50 | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | 3.86% | -3.67 | 1.31% | 14.40 | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | 3.86% | -3.67 | 1.31% | 14.40 | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | 3.86% | -3.67 | 1.31% | 14.34 | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | 3.86% | -3.66 | 1.27% | 14.20 | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | 3.86% | -3.65 | 1.27% | 14.12 | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | 3.87% | -3.65 | 1.27% | 14.05 | 7.50% |
| 2/15/2017 | 9.60% | 2.62% | 3.88% | -3.64 | 1.25% | 13.89 | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | 3.88% | -3.64 | 1.25% | 13.82 | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | 3.89% | -3.63 | 1.25% | 13.79 | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | 3.89% | -3.63 | 1.25% | 13.77 | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | 3.89% | -3.63 | 1.24% | 13.74 | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | 3.91% | -3.62 | 1.23% | 13.56 | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | 3.93% | -3.61 | 1.22% | 13.28 | 7.53% |
| 4/12/2017 | 9.40% | 2.74% | 3.94% | -3.60 | 1.20% | 13.06 | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | 3.95% | -3.59 | 1.19% | 13.05 | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | 3.98% | -3.58 | 1.19% | 12.95 | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | 4.00% | -3.57 | 1.18% | 12.88 | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | 4.01% | -3.56 | 1.18% | 12.88 | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | 4.02% | -3.56 | 1.18% | 12.87 | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | 4.05% | -3.54 | 1.16% | 12.69 | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | 4.06% | -3.54 | 1.16% | 12.66 | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | 4.06% | -3.54 | 1.16% | 12.66 | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | 4.09% | -3.52 | 1.14% | 12.24 | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | 4.10% | -3.52 | 1.13% | 11.95 | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | 4.07% | -3.53 | 1.14% | 11.47 | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | 4.06% | -3.53 | 1.14% | 11.42 | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | 4.04% | -3.54 | 1.13% | 11.23 | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | 4.03% | -3.54 | 1.13% | 11.22 | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | 4.03% | -3.54 | 1.13% | 11.22 | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | 4.03% | -3.54 | 1.13% | 11.22 | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | 4.03% | -3.54 | 1.12% | 11.15 | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | 4.01% | -3.54 | 1.12% | 11.14 | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | 4.00% | -3.55 | 1.12% | 11.11 | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | 4.00% | -3.55 | 1.12% | 11.11 | 7.12% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 12/5/2017 | 9.50% | 2.88% | 3.99% | -3.55 | 1.11% | 11.10 | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | 3.99% | -3.55 | 1.11% | 11.10 | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | 3.99% | -3.55 | 1.11% | 11.10 | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | 3.99% | -3.55 | 1.11% | 11.09 | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | 3.98% | -3.55 | 1.11% | 11.04 | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | 3.98% | -3.55 | 1.11% | 11.04 | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | 3.97% | -3.56 | 1.11% | 11.02 | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | 3.97% | -3.56 | 1.11% | 11.00 | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | 3.97% | -3.56 | 1.11% | 10.99 | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | 3.96% | -3.56 | 1.11% | 10.96 | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | 3.95% | -3.56 | 1.11% | 10.96 | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | 3.93% | -3.56 | 1.09% | 10.84 | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | 3.92% | -3.56 | 1.08% | 10.75 | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | 3.92% | -3.56 | 1.08% | 10.76 | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | 3.92% | -3.56 | 1.07% | 11.72 | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | 3.92% | -3.55 | 1.05% | 12.08 | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | 3.92% | -3.55 | 1.05% | 12.18 | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | 3.92% | -3.55 | 1.04% | 12.69 | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | 3.93% | -3.54 | 1.04% | 13.15 | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | 3.94% | -3.54 | 1.04% | 13.18 | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | 3.94% | -3.54 | 1.04% | 13.25 | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | 3.94% | -3.54 | 1.04% | 13.25 | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | 3.95% | -3.54 | 1.04% | 13.42 | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | 3.98% | -3.53 | 1.04% | 13.84 | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | 3.98% | -3.53 | 1.04% | 13.86 | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | 4.01% | -3.52 | 1.05% | 13.86 | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | 4.02% | -3.52 | 1.05% | 13.91 | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | 4.02% | -3.52 | 1.05% | 13.91 | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | 4.03% | -3.52 | 1.06% | 14.03 | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | 4.03% | -3.52 | 1.06% | 14.06 | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | 4.08% | -3.51 | 1.09% | 14.46 | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | 4.10% | -3.51 | 1.09% | 14.58 | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | 4.10% | -3.50 | 1.10% | 14.62 | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | 4.12% | -3.50 | 1.10% | 14.67 | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | 4.14% | -3.50 | 1.11% | 14.79 | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | 4.15% | -3.49 | 1.11% | 14.81 | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | 4.16% | -3.49 | 1.11% | 14.86 | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | 4.16% | -3.49 | 1.11% | 14.86 | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | 4.16% | -3.49 | 1.11% | 14.87 | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | 4.18% | -3.49 | 1.12% | 14.93 | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | 4.23% | -3.47 | 1.13% | 15.84 | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | 4.24% | -3.47 | 1.13% | 15.94 | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | 4.24% | -3.47 | 1.13% | 15.98 | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | 4.29% | -3.46 | 1.16% | 15.93 | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | 4.30% | -3.46 | 1.16% | 16.03 | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | 4.30% | -3.46 | 1.17% | 16.04 | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | 4.31% | -3.46 | 1.17% | 16.14 | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | 4.31% | -3.46 | 1.17% | 16.20 | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | 4.31% | -3.46 | 1.17% | 16.28 | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | 4.32% | -3.46 | 1.18% | 16.66 | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | 4.34% | -3.47 | 1.22% | 16.53 | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | 4.33% | -3.47 | 1.21% | 16.60 | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | 4.33% | -3.47 | 1.21% | 16.59 | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | 4.33% | -3.47 | 1.21% | 16.59 | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | 4.33% | -3.47 | 1.22% | 16.60 | 6.53% |
| 4/30/2019 | 9.73% | 3.11% | 4.31% | -3.47 | 1.20% | 16.53 | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | 4.31% | -3.47 | 1.20% | 16.53 | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | 4.30% | -3.47 | 1.20% | 16.54 | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | 4.30% | -3.47 | 1.20% | 16.55 | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | 4.30% | -3.47 | 1.20% | 16.63 | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | 4.29% | -3.48 | 1.20% | 16.75 | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | 4.29% | -3.48 | 1.20% | 16.78 | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | 4.28% | -3.48 | 1.19% | 16.88 | 6.81% |
| 8/12/2019 | 9.60% | 2.89% | 4.11% | -3.54 | 1.22% | 17.13 | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | 4.03% | -3.57 | 1.22% | 17.01 | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | 4.01% | -3.58 | 1.23% | 16.98 | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | 3.91% | -3.61 | 1.21% | 16.53 | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | 3.80% | -3.65 | 1.21% | 15.55 | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | 3.80% | -3.65 | 1.21% | 15.55 | 7.40% |
| 11/1/2019 | 9.35% | 2.59% | 3.80% | -3.65 | 1.20% | 15.52 | 6.76% |
| 11/29/2019 | 9.50% | 2.52% | 3.72% | -3.68 | 1.20% | 15.10 | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | 3.71% | -3.69 | 1.20% | 15.11 | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | 3.71% | -3.69 | 1.20% | 15.11 | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | 3.67% | -3.70 | 1.19% | 15.10 | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | 3.67% | -3.70 | 1.19% | 15.08 | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | 3.67% | -3.70 | 1.19% | 15.08 | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | 3.66% | -3.70 | 1.19% | 15.04 | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | 3.66% | -3.70 | 1.19% | 15.04 | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | 3.66% | -3.70 | 1.19% | 15.04 | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | 3.65% | -3.70 | 1.19% | 15.03 | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | 3.65% | -3.70 | 1.19% | 15.03 | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | 3.65% | -3.71 | 1.19% | 15.02 | 7.04% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 1/8/2020 | 10.02% | 2.43% | 3.61% | -3.72 | 1.19% | 14.99 | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | 3.59% | -3.73 | 1.18% | 14.95 | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | 3.58% | -3.73 | 1.19% | 14.94 | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | 3.58% | -3.73 | 1.19% | 14.93 | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | 3.53% | -3.75 | 1.18% | 15.13 | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | 3.51% | -3.76 | 1.18% | 15.16 | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | 3.50% | -3.76 | 1.18% | 15.16 | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | 3.49% | -3.77 | 1.18% | 15.16 | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | 3.48% | -3.78 | 1.18% | 15.16 | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | 3.46% | -3.78 | 1.18% | 15.36 | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | 3.41% | -3.81 | 1.19% | 16.54 | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | 3.41% | -3.83 | 1.24% | 19.18 | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | 3.39% | -3.88 | 1.32% | 21.82 | 7.63% |
| | | | | | | Average: | 6.05% |
| | | | | | | # of Rate Cases: | 751 |

Mr. O'Donnell's Proxy Group Capital Structure - Consolidated

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 57.26% | 58.49% | 58.29% | 59.20% | 58.22% | 58.12% | 58.26% | 57.91% | 58.22% |
| Alliant Energy Corporation | LNT | 44.45% | 43.24% | 45.34% | 45.45% | 44.27% | 44.24% | 46.28% | 46.19% | 44.93% |
| Ameren Corporation | AEE | 47.18% | 47.55% | 47.28% | 47.49% | 48.09% | 46.61% | 47.67% | 47.52% | 47.42% |
| American Electric Power Co. | AEP | 42.00% | 41.85% | 42.65% | 44.60% | 45.50% | 45.94% | 46.27% | 46.00% | 44.35% |
| CMS Energy Corporation | CMS | 27.24% | 28.04% | 28.66% | 28.93% | 30.32% | 30.65% | 30.71% | 30.09% | 29.33% |
| Consolidated Edison, Inc. | ED | 46.91% | 46.54% | 46.68% | 47.97% | 48.89% | 47.87% | 49.42% | 49.03% | 47.91% |
| Dominion Energy, Inc. | D | 41.58% | 39.80% | 39.97% | 36.59% | 34.36% | 34.00% | 33.75% | 33.50% | 36.69% |
| Duke Energy Corporation | DUK | 42.74% | 42.95% | 43.23% | 44.55% | 44.34% | 44.64% | 44.10% | 44.39% | 43.87% |
| Edison International | EIX | 41.88% | 38.51% | 38.65% | 41.55% | 45.13% | 45.13% | 45.79% | 49.05% | 43.21% |
| Entergy Corporation | ETR | 36.10% | 35.69% | 33.75% | 35.33% | 33.72% | 33.54% | 32.09% | 34.61% | 34.35% |
| Eversource Energy | ES | 44.79% | 45.21% | 45.82% | 45.55% | 46.41% | 46.38% | 46.03% | 47.33% | 45.94% |
| Hawaiian Electric Industries | HE | 51.16% | 50.63% | 50.09% | 52.91% | 53.77% | 53.40% | 54.66% | 54.75% | 52.67% |
| IDACORP, Inc. | IDA | 57.30% | 56.70% | 56.47% | 56.37% | 56.35% | 55.56% | 53.48% | 56.32% | 56.07% |
| MGE Energy, Inc. | MGEE | 62.36% | 61.80% | 61.65% | 62.04% | 61.94% | 65.38% | 65.12% | 64.81% | 63.14% |
| NextEra Energy, Inc. | NEE | 48.39% | 48.80% | 51.30% | 53.48% | 53.56% | 52.42% | 52.81% | 45.88% | 50.83% |
| NorthWestern Corporation | NWE | 47.67% | 47.94% | 48.59% | 47.76% | 48.24% | 48.28% | 47.34% | 49.74% | 48.19% |
| OGE Energy Corp. | OGE | 56.36% | 55.28% | 57.44% | 56.00% | 56.15% | 56.46% | 56.16% | 56.22% | 56.26% |
| Otter Tail Corporation | OTTR | 55.26% | 54.95% | 54.78% | 55.26% | 55.14% | 54.77% | 54.54% | 58.69% | 55.42% |
| Pinnacle West Capital Corp. | PNW | 50.18% | 49.92% | 49.98% | 50.41% | 51.27% | 51.22% | 50.74% | 50.68% | 50.55% |
| PNM Resources, Inc. | PNM | 35.82% | 35.57% | 35.23% | 38.74% | 40.39% | 39.91% | 39.47% | 41.02% | 38.27% |
| Portland General Electric Company | POR | 49.82% | 49.72% | 50.27% | 50.28% | 50.60% | 50.40% | 50.24% | 49.90% | 50.15% |
| Public Service Enterprise Group Incorporated | PEG | 48.56% | 48.51% | 50.72% | 49.85% | 50.00% | 50.17% | 51.90% | 51.44% | 50.14% |
| Sempra Energy | SRE | 41.40% | 38.85% | 40.20% | 39.71% | 39.56% | 38.70% | 38.37% | 41.48% | 39.78% |
| Southern Company | SO | 36.80% | 37.54% | 37.15% | 36.01% | 35.89% | 34.58% | 34.10% | 33.32% | 35.67% |
| WEC Energy Group | WEC | 46.35% | 48.28% | 48.18% | 48.59% | 50.74% | 50.58% | 50.24% | 49.67% | 49.08% |
| Xcel Energy Inc. | XEL | 40.20% | 40.11% | 40.79% | 42.99% | 43.09% | 41.88% | 43.56% | 43.34% | 42.00% |
| Mean | | 46.14% | 45.86% | 46.27% | 46.83% | 47.15% | 46.96% | 47.04% | 47.42% | 46.71% |

Mr. O'Donnell's Proxy Group Capital Structure - Consolidated

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 42.74% | 41.51% | 41.71% | 40.80% | 41.78% | 41.88% | 41.74% | 42.09% | 41.78% |
| Alliant  Energy Corporation | LNT | 55.55% | 56.76% | 54.66% | 54.55% | 55.73% | 55.76% | 53.72% | 53.81% | 55.07% |
| Ameren Corporation | AEE | 52.82% | 52.45% | 52.72% | 52.51% | 51.91% | 53.39% | 52.33% | 52.48% | 52.58% |
| American Electric Power Co. | AEP | 58.00% | 58.15% | 57.35% | 55.40% | 54.50% | 54.06% | 53.73% | 54.00% | 55.65% |
| CMS Energy Corporation | CMS | 72.76% | 71.96% | 71.34% | 71.07% | 69.68% | 69.35% | 69.29% | 69.91% | 70.67% |
| Consolidated Edison, Inc. | ED | 53.09% | 53.46% | 53.32% | 52.03% | 51.11% | 52.13% | 50.58% | 50.97% | 52.09% |
| Dominion Energy, Inc. | D | 58.42% | 60.20% | 60.03% | 63.41% | 65.64% | 66.00% | 66.25% | 66.50% | 63.31% |
| Duke Energy Corporation | DUK | 57.26% | 57.05% | 56.77% | 55.45% | 55.66% | 55.36% | 55.90% | 55.61% | 56.13% |
| Edison International | EIX | 58.12% | 61.49% | 61.35% | 58.45% | 54.87% | 54.87% | 54.21% | 50.95% | 56.79% |
| Entergy Corporation | ETR | 63.90% | 64.31% | 66.25% | 64.67% | 66.28% | 66.46% | 67.91% | 65.39% | 65.65% |
| Eversource Energy | ES | 55.21% | 54.79% | 54.18% | 54.45% | 53.59% | 53.62% | 53.97% | 52.67% | 54.06% |
| Hawaiian Electric Industries | HE | 48.84% | 49.37% | 49.91% | 47.09% | 46.23% | 46.60% | 45.34% | 45.25% | 47.33% |
| IDACORP, Inc. | IDA | 42.70% | 43.30% | 43.53% | 43.63% | 43.65% | 44.44% | 46.52% | 43.68% | 43.93% |
| MGE Energy, Inc. | MGEE | 37.64% | 38.20% | 38.35% | 37.96% | 38.06% | 34.62% | 34.88% | 35.19% | 36.86% |
| NextEra Energy, Inc. | NEE | 51.61% | 51.20% | 48.70% | 46.52% | 46.44% | 47.58% | 47.19% | 54.12% | 49.17% |
| NorthWestern Corporation | NWE | 52.33% | 52.06% | 51.41% | 52.24% | 51.76% | 51.72% | 52.66% | 50.26% | 51.81% |
| OGE Energy Corp. | OGE | 43.64% | 44.72% | 42.56% | 44.00% | 43.85% | 43.54% | 43.84% | 43.78% | 43.74% |
| Otter Tail Corporation | OTTR | 44.74% | 45.05% | 45.22% | 44.74% | 44.86% | 45.23% | 45.46% | 41.31% | 44.58% |
| Pinnacle West Capital Corp. | PNW | 49.82% | 50.08% | 50.02% | 49.59% | 48.73% | 48.78% | 49.26% | 49.32% | 49.45% |
| PNM Resources, Inc. | PNM | 64.18% | 64.43% | 64.77% | 61.26% | 59.61% | 60.09% | 60.53% | 58.98% | 61.73% |
| Portland General Electric Company | POR | 50.18% | 50.28% | 49.73% | 49.72% | 49.40% | 49.60% | 49.76% | 50.10% | 49.85% |
| Public Service Enterprise Group Incorporated | PEG | 51.44% | 51.49% | 49.28% | 50.15% | 50.00% | 49.83% | 48.10% | 48.56% | 49.86% |
| Sempra Energy | SRE | 58.60% | 61.15% | 59.80% | 60.29% | 60.44% | 61.30% | 61.63% | 58.52% | 60.22% |
| Southern Company | SO | 63.20% | 62.46% | 62.85% | 63.99% | 64.11% | 65.42% | 65.90% | 66.68% | 64.33% |
| WEC Energy Group | WEC | 53.65% | 51.72% | 51.82% | 51.41% | 49.26% | 49.42% | 49.76% | 50.33% | 50.92% |
| Xcel Energy Inc. | XEL | 59.80% | 59.89% | 59.21% | 57.01% | 56.91% | 58.12% | 56.44% | 56.66% | 58.00% |
| Mean | | 53.86% | 54.14% | 53.73% | 53.17% | 52.85% | 53.04% | 52.96% | 52.58% | 53.29% |

Mr. O'Donnell's Proxy Group Capital Structure - Operating Company Level

| | | | | | | % Common Equity | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 58.68% | 59.66% | 59.53% | 59.12% | 58.50% | 58.84% | 63.09% | 62.51% | 59.99% |
| Alliant Energy Corporation | LNT | 51.73% | 50.38% | 53.18% | 53.11% | 51.13% | 51.00% | 49.74% | 49.77% | 51.26% |
| Ameren Corporation | AEE | 53.67% | 53.03% | 52.81% | 52.69% | 53.22% | 52.01% | 53.04% | 52.65% | 52.89% |
| American Electric Power Co. | AEP | 49.91% | 48.80% | 49.62% | 49.40% | 48.68% | 48.52% | 48.60% | 48.91% | 49.06% |
| CMS Energy Corporation | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison, Inc. | ED | 49.85% | 49.08% | 48.75% | 47.97% | 48.38% | 48.73% | 49.75% | 49.23% | 48.97% |
| Dominion Energy, Inc. | D | 53.56% | 50.98% | 50.47% | 48.75% | 51.63% | 51.12% | 50.17% | 50.62% | 50.91% |
| Duke Energy Corporation | DUK | 52.89% | 54.48% | 53.14% | 54.35% | 55.03% | 54.94% | 54.46% | 54.30% | 54.20% |
| Edison International | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Corporation | ETR | 49.10% | 48.19% | 48.81% | 50.11% | 49.96% | 49.95% | 48.60% | 48.97% | 49.21% |
| Eversource Energy | ES | 49.53% | 49.38% | 54.22% | 53.28% | 51.03% | 50.14% | 54.05% | 54.60% | 52.03% |
| Hawaiian Electric Industries | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| IDACORP, Inc. | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| MGE Energy, Inc. | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| NextEra Energy, Inc. | NEE | 56.15% | 61.22% | 61.05% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 61.20% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| OGE Energy Corp. | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Corporation | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Pinnacle West Capital Corp. | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| PNM Resources, Inc. | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Public Service Enterprise Group Incorporated | PEG | 54.65% | 54.31% | 55.14% | 54.24% | 53.69% | 53.93% | 54.20% | 53.41% | 54.20% |
| Sempra Energy | SRE | 56.17% | 56.30% | 53.82% | 53.29% | 53.13% | 54.39% | 54.20% | 53.27% | 54.32% |
| Southern Company | SO | 52.36% | 52.93% | 52.80% | 54.21% | 51.50% | 50.31% | 49.98% | 47.67% | 51.47% |
| WEC Energy Group | WEC | 55.79% | 56.71% | 55.73% | 53.46% | 58.30% | 57.72% | 61.62% | 54.62% | 56.74% |
| Xcel Energy Inc. | XEL | 53.98% | 54.70% | 54.51% | 54.22% | 53.37% | 53.63% | 54.15% | 53.95% | 54.06% |
| Mean | | 53.18% | 53.04% | 53.03% | 52.87% | 53.08% | 52.90% | 53.19% | 53.10% | 53.05% |

Operating Company Capital Structure

| | | | | | | % Common Equity | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 59.33% | 60.94% | 60.87% | 61.39% | 60.43% | 60.33% | 60.38% | 60.04% | 60.46% |
| Superior Water, Light and Power Company | ALE | 58.03% | 58.38% | 58.19% | 56.86% | 56.58% | 57.34% | 65.80% | 64.99% | 59.52% |
| Interstate Power and Light Company | LNT | 50.06% | 51.76% | 53.33% | 53.52% | 49.64% | 50.47% | 49.92% | 50.31% | 51.13% |
| Wisconsin Power and Light Company | LNT | 53.40% | 49.01% | 53.03% | 52.69% | 52.62% | 51.52% | 49.57% | 49.23% | 51.38% |
| Ameren Illinois Company | AEE | 54.46% | 54.05% | 53.65% | 52.86% | 53.18% | 52.74% | 54.24% | 53.38% | 53.57% |
| Union Electric Company | AEE | 52.88% | 52.00% | 51.96% | 52.52% | 53.26% | 51.28% | 51.84% | 51.92% | 52.21% |
| AEP Texas Inc. | AEP | 46.97% | 46.32% | 47.54% | 45.38% | 43.80% | 43.20% | 46.75% | 45.14% | 45.64% |
| Appalachian Power Company | AEP | 48.74% | 48.19% | 47.77% | 49.51% | 49.30% | 48.93% | 49.35% | 48.72% | 48.81% |
| Indiana Michigan Power Company | AEP | 46.51% | 45.83% | 45.43% | 44.62% | 44.53% | 44.15% | 46.64% | 46.33% | 45.50% |
| Kentucky Power Company | AEP | 46.94% | 46.50% | 46.42% | 45.72% | 45.28% | 44.89% | 44.40% | 43.52% | 45.46% |
| Kingsport Power Company | AEP | 54.24% | 50.18% | 51.54% | 50.79% | 50.71% | 47.69% | 47.28% | 46.53% | 49.87% |
| Ohio Power Company | AEP | 53.63% | 52.92% | 58.86% | 57.80% | 56.85% | 57.11% | 52.91% | 58.63% | 56.09% |
| Public Service Company of Oklahoma | AEP | 49.89% | 48.02% | 47.19% | 49.16% | 49.55% | 48.59% | 48.10% | 48.50% | 48.62% |
| Southwestern Electric Power Company | AEP | 48.63% | 47.45% | 47.59% | 46.97% | 43.43% | 47.91% | 47.72% | 48.52% | 47.28% |
| Wheeling Power Company | AEP | 53.66% | 53.83% | 54.27% | 54.62% | 54.70% | 54.19% | 54.27% | 54.26% | 54.23% |
| Consumers Energy Company | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison Company of New York, Inc. | ED | 49.29% | 48.92% | 48.30% | 47.52% | 48.33% | 46.72% | 48.66% | 48.22% | 48.24% |
| Orange and Rockland Utilities, Inc. | ED | 50.40% | 49.25% | 49.21% | 48.41% | 48.44% | 50.74% | 50.83% | 50.25% | 49.69% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 53.33% | 53.30% | 52.42% | 52.62% | 53.64% | 52.81% | 51.03% | 51.71% | 52.61% |
| Dominion Energy South Carolina, Inc. | D | 53.80% | 48.67% | 48.52% | 44.88% | 49.63% | 49.44% | 49.30% | 49.54% | 49.22% |
| Duke Energy Carolinas, LLC | DUK | 51.80% | 52.94% | 52.32% | 51.78% | 52.64% | 52.10% | 51.70% | 52.98% | 52.28% |
| Duke Energy Florida, LLC | DUK | 52.82% | 51.55% | 50.56% | 50.04% | 49.65% | 48.79% | 49.92% | 49.25% | 50.32% |
| Duke Energy Indiana, LLC | DUK | 51.52% | 54.83% | 54.29% | 53.26% | 52.79% | 52.64% | 52.54% | 51.94% | 52.98% |
| Duke Energy Kentucky, Inc. | DUK | 45.44% | 53.04% | 52.81% | 51.95% | 56.58% | 55.79% | 53.72% | 53.11% | 52.80% |
| Duke Energy Ohio, Inc. | DUK | 64.90% | 64.45% | 59.29% | 68.09% | 67.73% | 67.10% | 66.06% | 66.24% | 65.48% |
| Duke Energy Progress, LLC | DUK | 50.86% | 50.09% | 49.60% | 51.00% | 50.76% | 53.22% | 52.82% | 52.27% | 51.33% |
| Southern California Edison Company | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Arkansas, LLC | ETR | 47.72% | 46.49% | 47.04% | 49.42% | 49.38% | 48.29% | 45.88% | 45.95% | 47.52% |
| Entergy Louisiana, LLC | ETR | 47.13% | 46.32% | 45.79% | 47.37% | 46.77% | 46.97% | 44.58% | 47.43% | 46.55% |
| Entergy Mississippi, LLC | ETR | 48.35% | 44.93% | 49.41% | 49.11% | 50.10% | 49.10% | 48.32% | 47.85% | 48.40% |
| Entergy New Orleans, LLC | ETR | 53.69% | 52.40% | 51.69% | 51.19% | 50.93% | 54.02% | 53.43% | 53.16% | 52.56% |
| Entergy Texas, Inc. | ETR | 48.63% | 50.79% | 50.13% | 53.46% | 52.61% | 51.38% | 50.79% | 50.45% | 51.03% |
| Connecticut Light and Power Company | ES | 54.12% | 55.38% | 58.18% | 56.18% | 54.49% | 53.85% | 50.40% | 53.82% | 54.55% |
| NSTAR Electric Company | ES | 53.81% | 52.74% | 56.08% | 55.74% | 55.50% | 54.51% | 53.83% | 53.85% | 54.51% |
| Public Service Company of New Hampshire | ES | 40.64% | 40.02% | 48.38% | 47.92% | 43.11% | 42.06% | 57.93% | 57.30% | 47.17% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 53.43% | 53.43% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| Madison Gas and Electric Company | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| Florida Power & Light Company | NEE | 59.78% | 61.30% | 64.03% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 62.03% |
| Gulf Power Company | NEE | 52.52% | 61.15% | 58.06% | NA | NA | NA | NA | NA | 57.24% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| Oklahoma Gas and Electric Company | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Power Company | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Arizona Public Service Company | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| Public Service Company of New Mexico | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Public Service Electric and Gas Company | PEG | 54.65% | 54.31% | 55.14% | 54.24% | 53.69% | 53.93% | 54.20% | 53.41% | 54.20% |
| Oncor Electric Delivery Company LLC | SRE | 54.91% | 57.43% | 59.79% | 59.47% | 59.29% | 62.31% | 60.34% | 58.86% | 59.05% |
| San Diego Gas & Electric Company | SRE | 57.43% | 55.17% | 56.60% | 55.79% | 55.17% | 54.47% | 55.92% | 55.09% | 55.71% |
| Sharyland Utilities, LLC | SRE | NA | NA | 45.05% | 44.62% | 44.92% | 46.39% | 46.34% | 45.86% | 45.53% |
| Alabama Power Company | SO | 51.45% | 52.54% | 52.23% | 47.77% | 48.13% | 47.51% | 48.86% | 47.07% | 49.44% |
| Georgia Power Company | SO | 55.38% | 56.39% | 56.43% | 59.02% | 57.27% | 54.97% | 53.81% | 50.06% | 55.42% |
| Mississippi Power Company | SO | 50.23% | 49.87% | 49.73% | 50.35% | 45.28% | 43.87% | 43.00% | 39.34% | 46.46% |
| Gulf Power Company | SO | NA | NA | NA | 59.73% | 55.34% | 54.90% | 54.27% | 54.19% | 55.69% |
| Upper Michigan Energy Resources Corporation | WEC | 56.09% | 54.45% | 52.54% | 47.01% | 55.08% | 54.53% | 70.04% | 49.85% | 54.95% |
| Wisconsin Electric Power Company | WEC | 56.92% | 56.64% | 55.78% | 56.03% | 59.25% | 59.09% | 56.47% | 55.94% | 57.01% |
| Wisconsin Public Service Corporation | WEC | 54.37% | 59.04% | 58.88% | 57.33% | 60.59% | 59.53% | 58.35% | 58.06% | 58.27% |
| Northern States Power Company - MN | XEL | 51.79% | 53.66% | 53.64% | 52.81% | 52.64% | 52.61% | 52.59% | 52.38% | 52.77% |
| Northern States Power Company - WI | XEL | 53.56% | 53.49% | 53.59% | 53.60% | 48.45% | 53.85% | 53.79% | 53.36% | 52.96% |
| Public Service Company of Colorado | XEL | 56.35% | 57.53% | 56.68% | 56.31% | 56.08% | 54.17% | 56.67% | 56.50% | 56.29% |
| Southwestern Public Service Company | XEL | 54.21% | 54.14% | 54.13% | 54.17% | 56.29% | 53.88% | 53.54% | 53.55% | 54.24% |
| Mean | | 52.54% | 52.50% | 52.65% | 52.49% | 52.45% | 52.27% | 52.61% | 52.27% | 52.52% |

Source: S&P Global Market Intelligence

Mr. O'Donnell's Proxy Group Capital Structure - Operating Company Level

| | | | | | | % Long-Term Debt | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 41.32% | 40.34% | 40.47% | 40.88% | 41.50% | 41.16% | 36.91% | 37.49% | 40.01% |
| Alliant Energy Corporation | LNT | 48.27% | 49.62% | 46.82% | 46.89% | 48.87% | 49.00% | 50.26% | 50.23% | 48.74% |
| Ameren Corporation | AEE | 46.33% | 46.97% | 47.19% | 47.31% | 46.78% | 47.99% | 46.96% | 47.35% | 47.11% |
| American Electric Power Co. | AEP | 50.09% | 51.20% | 50.38% | 50.60% | 51.32% | 51.48% | 51.40% | 51.09% | 50.94% |
| CMS Energy Corporation | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison, Inc. | ED | 50.15% | 50.92% | 51.25% | 52.03% | 51.62% | 51.27% | 50.25% | 50.77% | 51.03% |
| Dominion Energy, Inc. | D | 46.44% | 49.02% | 49.53% | 51.25% | 48.37% | 48.88% | 49.83% | 49.38% | 49.09% |
| Duke Energy Corporation | DUK | 47.11% | 45.52% | 46.86% | 45.65% | 44.97% | 45.06% | 45.54% | 45.70% | 45.80% |
| Edison International | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Corporation | ETR | 50.90% | 51.81% | 51.19% | 49.89% | 50.04% | 50.05% | 51.40% | 51.03% | 50.79% |
| Eversource Energy | ES | 50.47% | 50.62% | 45.78% | 46.72% | 48.97% | 49.86% | 45.95% | 45.40% | 47.97% |
| Hawaiian Electric Industries | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| IDACORP, Inc. | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| MGE Energy, Inc. | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| NextEra Energy, Inc. | NEE | 43.85% | 38.78% | 38.95% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 38.80% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| OGE Energy Corp. | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Corporation | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Pinnacle West Capital Corp. | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| PNM Resources, Inc. | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Public Service Enterprise Group Incorporated | PEG | 45.35% | 45.69% | 44.86% | 45.76% | 46.31% | 46.07% | 45.80% | 46.59% | 45.80% |
| Sempra Energy | SRE | 43.83% | 43.70% | 46.18% | 46.71% | 46.87% | 45.61% | 45.80% | 46.73% | 45.68% |
| Southern Company | SO | 47.64% | 47.07% | 47.20% | 45.79% | 48.50% | 49.69% | 50.02% | 52.33% | 48.53% |
| WEC Energy Group | WEC | 44.21% | 43.29% | 44.27% | 46.54% | 41.70% | 42.28% | 38.38% | 45.38% | 43.26% |
| Xcel Energy Inc. | XEL | 46.02% | 45.30% | 45.49% | 45.78% | 46.63% | 46.37% | 45.85% | 46.05% | 45.94% |
| Mean | | 46.82% | 46.96% | 46.97% | 47.13% | 46.92% | 47.10% | 46.81% | 46.90% | 46.95% |

Operating Company Capital Structure

| | | | | | | % Long-Term Debt | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 40.67% | 39.06% | 39.13% | 38.61% | 39.57% | 39.67% | 39.62% | 39.96% | 39.54% |
| Superior Water, Light and Power Company | ALE | 41.97% | 41.62% | 41.81% | 43.14% | 43.42% | 42.66% | 34.20% | 35.01% | 40.48% |
| Interstate Power and Light Company | LNT | 49.94% | 48.24% | 46.67% | 46.48% | 50.36% | 49.53% | 50.08% | 49.69% | 48.87% |
| Wisconsin Power and Light Company | LNT | 46.60% | 50.99% | 46.97% | 47.31% | 47.38% | 48.48% | 50.43% | 50.77% | 48.62% |
| Ameren Illinois Company | AEE | 45.54% | 45.95% | 46.35% | 47.14% | 46.82% | 47.26% | 45.76% | 46.62% | 46.43% |
| Union Electric Company | AEE | 47.12% | 48.00% | 48.04% | 47.48% | 46.74% | 48.72% | 48.16% | 48.08% | 47.79% |
| AEP Texas Inc. | AEP | 53.03% | 53.68% | 52.46% | 54.62% | 56.20% | 56.80% | 53.25% | 54.86% | 54.36% |
| Appalachian Power Company | AEP | 51.26% | 51.81% | 52.23% | 50.49% | 50.70% | 51.07% | 50.65% | 51.28% | 51.19% |
| Indiana Michigan Power Company | AEP | 53.49% | 54.17% | 54.57% | 55.38% | 55.47% | 55.85% | 53.36% | 53.67% | 54.50% |
| Kentucky Power Company | AEP | 53.06% | 53.50% | 53.58% | 54.28% | 54.72% | 55.11% | 55.60% | 56.48% | 54.54% |
| Kingsport Power Company | AEP | 45.76% | 49.82% | 48.46% | 49.21% | 49.29% | 52.31% | 52.72% | 53.47% | 50.13% |
| Ohio Power Company | AEP | 46.37% | 47.08% | 41.14% | 42.20% | 43.15% | 42.89% | 47.09% | 41.37% | 43.91% |
| Public Service Company of Oklahoma | AEP | 50.11% | 51.98% | 52.81% | 50.84% | 50.45% | 51.41% | 51.90% | 51.50% | 51.38% |
| Southwestern Electric Power Company | AEP | 51.37% | 52.55% | 52.41% | 53.03% | 56.57% | 52.09% | 52.28% | 51.48% | 52.72% |
| Wheeling Power Company | AEP | 46.34% | 46.17% | 45.73% | 45.38% | 45.30% | 45.81% | 45.73% | 45.74% | 45.77% |
| Consumers Energy Company | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison Company of New York, Inc. | ED | 50.71% | 51.08% | 51.70% | 52.48% | 51.67% | 53.28% | 51.34% | 51.78% | 51.76% |
| Orange and Rockland Utilities, Inc. | ED | 49.60% | 50.75% | 50.79% | 51.59% | 51.56% | 49.26% | 49.17% | 49.75% | 50.31% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 46.67% | 46.70% | 47.58% | 47.38% | 46.36% | 47.19% | 48.97% | 48.29% | 47.39% |
| Dominion Energy South Carolina, Inc. | D | 46.20% | 51.33% | 51.48% | 55.12% | 50.37% | 50.56% | 50.70% | 50.46% | 50.78% |
| Duke Energy Carolinas, LLC | DUK | 48.20% | 47.06% | 47.68% | 48.22% | 47.36% | 47.90% | 48.30% | 47.02% | 47.72% |
| Duke Energy Florida, LLC | DUK | 47.18% | 48.45% | 49.44% | 49.96% | 50.35% | 51.21% | 50.08% | 50.75% | 49.68% |
| Duke Energy Indiana, LLC | DUK | 48.48% | 45.17% | 45.71% | 46.74% | 47.21% | 47.36% | 47.46% | 48.06% | 47.02% |
| Duke Energy Kentucky, Inc. | DUK | 54.56% | 46.96% | 47.19% | 48.05% | 43.42% | 44.21% | 46.28% | 46.89% | 47.20% |
| Duke Energy Ohio, Inc. | DUK | 35.10% | 35.55% | 40.71% | 31.91% | 32.27% | 32.90% | 33.94% | 33.76% | 34.52% |
| Duke Energy Progress, LLC | DUK | 49.14% | 49.91% | 50.40% | 49.00% | 49.24% | 46.78% | 47.18% | 47.73% | 48.67% |
| Southern California Edison Company | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Arkansas, LLC | ETR | 52.28% | 53.51% | 52.96% | 50.58% | 50.62% | 51.71% | 54.12% | 54.05% | 52.48% |
| Entergy Louisiana, LLC | ETR | 52.87% | 53.68% | 54.21% | 52.63% | 53.23% | 53.03% | 55.42% | 52.57% | 53.45% |
| Entergy Mississippi, LLC | ETR | 51.65% | 55.07% | 50.59% | 50.89% | 49.90% | 50.90% | 51.68% | 52.15% | 51.60% |
| Entergy New Orleans, LLC | ETR | 46.31% | 47.60% | 48.31% | 48.81% | 49.07% | 45.98% | 46.57% | 46.84% | 47.44% |
| Entergy Texas, Inc. | ETR | 51.37% | 49.21% | 49.87% | 46.54% | 47.39% | 48.62% | 49.21% | 49.55% | 48.97% |
| Connecticut Light and Power Company | ES | 45.88% | 44.62% | 41.82% | 43.82% | 45.51% | 46.15% | 49.60% | 46.18% | 45.45% |
| NSTAR Electric Company | ES | 46.19% | 47.26% | 43.92% | 44.26% | 44.50% | 45.49% | 46.17% | 46.15% | 45.49% |
| Public Service Company of New Hampshire | ES | 59.36% | 59.98% | 51.62% | 52.08% | 56.89% | 57.94% | 42.07% | 42.70% | 52.83% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 46.57% | 46.57% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| Madison Gas and Electric Company | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| Florida Power & Light Company | NEE | 40.22% | 38.70% | 35.97% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 37.97% |
| Gulf Power Company | NEE | 47.48% | 38.85% | 41.94% | NA | NA | NA | NA | NA | 42.76% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| Oklahoma Gas and Electric Company | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Power Company | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Arizona Public Service Company | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| Public Service Company of New Mexico | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Public Service Electric and Gas Company | PEG | 45.35% | 45.69% | 44.86% | 45.76% | 46.31% | 46.07% | 45.80% | 46.59% | 45.80% |
| Oncor Electric Delivery Company LLC | SRE | 45.09% | 42.57% | 40.21% | 40.53% | 40.71% | 37.69% | 39.66% | 41.14% | 40.95% |
| San Diego Gas & Electric Company | SRE | 42.57% | 44.83% | 43.40% | 44.21% | 44.83% | 45.53% | 44.08% | 44.91% | 44.29% |
| Sharyland Utilities, LLC | SRE | NA | NA | 54.95% | 55.38% | 55.08% | 53.61% | 53.66% | 54.14% | 54.47% |
| Alabama Power Company | SO | 48.55% | 47.46% | 47.77% | 52.23% | 51.87% | 52.49% | 51.14% | 52.93% | 50.56% |
| Georgia Power Company | SO | 44.62% | 43.61% | 43.57% | 40.98% | 42.73% | 45.03% | 46.19% | 49.94% | 44.58% |
| Mississippi Power Company | SO | 49.77% | 50.13% | 50.27% | 49.65% | 54.72% | 56.13% | 57.00% | 60.66% | 53.54% |
| Gulf Power Company | SO | NA | NA | NA | 40.27% | 44.66% | 45.10% | 45.73% | 45.81% | 44.31% |
| Upper Michigan Energy Resources Corporation | WEC | 43.91% | 45.55% | 47.46% | 52.99% | 44.92% | 45.47% | 29.96% | 50.15% | 45.05% |
| Wisconsin Electric Power Company | WEC | 43.08% | 43.36% | 44.22% | 43.97% | 40.75% | 40.91% | 43.53% | 44.06% | 42.99% |
| Wisconsin Public Service Corporation | WEC | 45.63% | 40.96% | 41.12% | 42.67% | 39.41% | 40.47% | 41.65% | 41.94% | 41.73% |
| Northern States Power Company - MN | XEL | 48.21% | 46.34% | 46.36% | 47.19% | 47.36% | 47.39% | 47.41% | 47.62% | 47.23% |
| Northern States Power Company - WI | XEL | 46.44% | 46.51% | 46.41% | 46.40% | 51.55% | 46.15% | 46.21% | 46.64% | 47.04% |
| Public Service Company of Colorado | XEL | 43.65% | 42.47% | 43.32% | 43.69% | 43.92% | 45.83% | 43.33% | 43.50% | 43.71% |
| Southwestern Public Service Company | XEL | 45.79% | 45.86% | 45.87% | 45.83% | 43.71% | 46.12% | 46.46% | 46.45% | 45.76% |
| Mean | | 47.46% | 47.50% | 47.35% | 47.51% | 47.55% | 47.73% | 47.39% | 47.73% | 47.48% |

Recently Authorized ROEs by RRA Ranking

| | | | | | | | | Electric Utilities | | |
|---|---|---|---|---|---|---|---|---|---|---|
| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
| Washington | Avista Corp. | D-UE-150204 | Electric | Vertically Integrated | 1/6/2016 | 9.50 | Average / 3 | | | 9.50 |
| Arkansas | Entergy Arkansas LLC | D-15-015-U | Electric | Vertically Integrated | 2/23/2016 | 9.75 | Average / 3 | | | 9.75 |
| Indiana | Indianapolis Power & Light Co. | Ca-44576 | Electric | Vertically Integrated | 3/16/2016 | 9.85 | Above Average / 3 | 9.85 | | |
| New Mexico | El Paso Electric Co. | C-15-00127-UT | Electric | Vertically Integrated | 6/8/2016 | 9.48 | Below Average / 1 | | | 9.48 |
| Indiana | Northern IN Public Svc Co. | Ca-44688 | Electric | Vertically Integrated | 7/18/2016 | 9.98 | Above Average / 3 | 9.98 | | |
| Tennessee | Kingsport Power Company | D-16-00001 | Electric | Vertically Integrated | 8/9/2016 | 9.85 | Average / 1 | 9.85 | | |
| Arizona | UNS Electric Inc. | D-E-04204A-15-0142 | Electric | Vertically Integrated | 8/18/2016 | 9.50 | Average / 3 | | | 9.50 |
| Washington | PacifiCorp | D-UE-152253 | Electric | Vertically Integrated | 9/1/2016 | 9.50 | Average / 3 | | | 9.50 |
| Michigan | Upper Peninsula Power Co. | C-U-17895 | Electric | Vertically Integrated | 9/8/2016 | 10.00 | Average / 1 | 10.00 | | |
| New Mexico | Public Service Co. of NM | C-15-00261-UT | Electric | Vertically Integrated | 9/28/2016 | 9.58 | Below Average / 1 | | | 9.58 |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-121 (Elec) | Electric | Vertically Integrated | 11/9/2016 | 9.80 | Above Average / 2 | 9.80 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201500208 | Electric | Vertically Integrated | 11/10/2016 | 9.50 | Average / 2 | | 9.50 | |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-120 (Elec) | Electric | Vertically Integrated | 11/18/2016 | 10.00 | Above Average / 2 | 10.00 | | |
| Florida | Florida Power & Light Co. | D-160021-EI | Electric | Vertically Integrated | 11/29/2016 | 10.55 | Above Average / 3 | 10.55 | | |
| California | Lbrty Utilities (CalPeco Elect | A-15-05-008 | Electric | Vertically Integrated | 12/1/2016 | 10.00 | Average / 1 | 10.00 | | |
| South Carolina | Duke Energy Progress LLC | D-2016-227-E | Electric | Vertically Integrated | 12/7/2016 | 10.10 | Average / 1 | 10.10 | | |
| Colorado | Black Hills Colorado Electric | D-16AL-0326E | Electric | Vertically Integrated | 12/19/2016 | 9.37 | Average / 1 | 9.37 | | |
| Nevada | Sierra Pacific Power Co. | D-16-06006 | Electric | Vertically Integrated | 12/22/2016 | 9.60 | Average / 2 | | 9.60 | |
| North Carolina | Virginia Electric & Power Co. | D-E-22, Sub 532 | Electric | Vertically Integrated | 12/22/2016 | 9.90 | Average / 1 | 9.90 | | |
| Idaho | Avista Corp. | C-AVU-E-16-03 | Electric | Vertically Integrated | 12/28/2016 | 9.50 | Average / 2 | | 9.50 | |
| Wyoming | MDU Resources Group Inc. | D-20004-117-ER-16 | Electric | Vertically Integrated | 1/18/2017 | 9.45 | Average / 2 | | 9.45 | |
| Michigan | DTE Electric Co. | C-U-18014 | Electric | Vertically Integrated | 1/31/2017 | 10.10 | Average / 1 | 10.10 | | |
| Arizona | Tucson Electric Power Co. | D-E-01933A-15-0322 | Electric | Vertically Integrated | 2/24/2017 | 9.75 | Average / 3 | | | 9.75 |
| Michigan | Consumers Energy Co. | C-U-17990 | Electric | Vertically Integrated | 2/28/2017 | 10.10 | Average / 1 | 10.10 | | |
| Minnesota | Otter Tail Power Co. | D-E-017/GR-15-1033 | Electric | Vertically Integrated | 3/2/2017 | 9.41 | Average / 2 | | 9.41 | |
| Oklahoma | Oklahoma Gas and Electric Co. | Ca-PUD201500273 | Electric | Vertically Integrated | 3/20/2017 | 9.50 | Average / 2 | | 9.50 | |
| Florida | Gulf Power Co. | D-160186-EI | Electric | Vertically Integrated | 4/4/2017 | 10.25 | Above Average / 3 | 10.25 | | |
| Missouri | Kansas City Power & Light | C-ER-2016-0285 | Electric | Vertically Integrated | 5/3/2017 | 9.50 | Average / 2 | | 9.50 | |
| Minnesota | Northern States Power Co. - MN | D-E-002/GR-15-826 | Electric | Vertically Integrated | 5/11/2017 | 9.20 | Average / 2 | | 9.20 | |
| Arkansas | Oklahoma Gas and Electric Co. | D-16-052-U | Electric | Vertically Integrated | 5/18/2017 | 9.50 | Average / 1 | 9.50 | | |
| North Dakota | MDU Resources Group Inc. | C-PU-16-666 | Electric | Vertically Integrated | 6/16/2017 | 9.65 | Average / 1 | 9.65 | | |
| Kentucky | Kentucky Utilities Co. | C-2016-00370 | Electric | Vertically Integrated | 6/22/2017 | 9.70 | Average / 1 | 9.70 | | |
| Kentucky | Louisville Gas & Electric Co. | C-2016-00371 (elec.) | Electric | Vertically Integrated | 6/22/2017 | 9.70 | Average / 1 | 9.70 | | |
| Arizona | Arizona Public Service Co. | D-E-01345A-16-0036 | Electric | Vertically Integrated | 8/15/2017 | 10.00 | Average / 3 | | | 10.00 |
| California | San Diego Gas & Electric Co. | Advice No. 3120-E | Electric | Vertically Integrated | 10/26/2017 | 10.20 | Above Average / 3 | 10.20 | | |
| California | Pacific Gas and Electric Co. | Advise No. 3887-G/5148-E | Electric | Vertically Integrated | 10/26/2017 | 10.25 | Above Average / 3 | 10.25 | | |
| California | Southern California Edison Co. | Advice No. 3665-E | Electric | Vertically Integrated | 10/26/2017 | 10.30 | Above Average / 3 | 10.30 | | |
| Florida | Tampa Electric Co. | D-20170210-EI | Electric | Vertically Integrated | 11/6/2017 | 10.25 | Above Average / 2 | 10.25 | | |
| Alaska | Alaska Electric Light Power | D-U-16-086 | Electric | Vertically Integrated | 11/15/2017 | 11.95 | Below Average / 1 | | | 11.95 |
| Washington | Puget Sound Energy Inc. | D-UE-170033 | Electric | Vertically Integrated | 12/5/2017 | 9.50 | Average / 3 | | | 9.50 |
| Wisconsin | Northern States Power Co - WI | D-4220-UR-123 (Elec) | Electric | Vertically Integrated | 12/7/2017 | 9.80 | Above Average / 2 | 9.80 | | |
| Texas | Southwestern Electric Power Co | D-46449 | Electric | Vertically Integrated | 12/14/2017 | 9.60 | Average / 3 | | | 9.60 |
| Texas | El Paso Electric Co. | D-46831 | Electric | Vertically Integrated | 12/14/2017 | 9.65 | Average / 3 | | | 9.65 |
| Oregon | Portland General Electric Co. | D-UE-319 | Electric | Vertically Integrated | 12/18/2017 | 9.50 | Average / 2 | | 9.50 | |
| New Mexico | Public Service Co. of NM | C-16-00276-UT | Electric | Vertically Integrated | 12/20/2017 | 9.58 | Below Average / 2 | | | 9.58 |
| Vermont | Green Mountain Power Corp. | C-17-3112-INV | Electric | Vertically Integrated | 12/21/2017 | 9.10 | Average / 2 | | 9.10 | |
| Idaho | Avista Corp. | C-AVU-E-17-01 | Electric | Vertically Integrated | 12/28/2017 | 9.50 | Average / 2 | | 9.50 | |
| Nevada | Nevada Power Co. | D-17-06003 | Electric | Vertically Integrated | 12/29/2017 | 9.51 | Average / 2 | | 9.51 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|
| Kentucky | Kentucky Power Co. | C-2017-00179 | Electric | Vertically Integrated | 1/18/2018 | 9.70 | Average / 1 | 9.70 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201700151 | Electric | Vertically Integrated | 1/31/2018 | 9.30 | Average / 3 | | | 9.30 |
| Iowa | Interstate Power & Light Co. | D-RPU-2017-0001 | Electric | Vertically Integrated | 2/2/2018 | 9.98 | Average / 1 | 9.98 | | |
| North Carolina | Duke Energy Progress LLC | D-E-2, Sub 1142 | Electric | Vertically Integrated | 2/23/2018 | 9.90 | Average / 1 | 9.90 | | |
| Minnesota | ALLETE (Minnesota Power) | D-E-015/GR-16-664 | Electric | Vertically Integrated | 3/12/2018 | 9.25 | Average / 2 | | 9.25 | |
| Michigan | Consumers Energy Co. | C-U-18322 | Electric | Vertically Integrated | 3/29/2018 | 10.00 | Above Average / 3 | 10.00 | | |
| Michigan | Indiana Michigan Power Co. | C-U-18370 | Electric | Vertically Integrated | 4/12/2018 | 9.90 | Above Average / 3 | 9.90 | | |
| Kentucky | Duke Energy Kentucky Inc. | C-2017-00321 | Electric | Vertically Integrated | 4/13/2018 | 9.73 | Average / 1 | 9.73 | | |
| Michigan | DTE Electric Co. | C-U-18255 | Electric | Vertically Integrated | 4/18/2018 | 10.00 | Above Average / 3 | 10.00 | | |
| Washington | Avista Corp. | D-UE-170485 | Electric | Vertically Integrated | 4/26/2018 | 9.50 | Average / 3 | | | 9.50 |
| Indiana | Indiana Michigan Power Co. | Ca-44967 | Electric | Vertically Integrated | 5/30/2018 | 9.95 | Average / 1 | 9.95 | | |
| Hawaii | Hawaiian Electric Co. | D-2016-0328 | Electric | Vertically Integrated | 6/22/2018 | 9.50 | Average / 2 | | 9.50 | |
| North Carolina | Duke Energy Carolinas LLC | D-E-7, Sub 1146 | Electric | Vertically Integrated | 6/22/2018 | 9.90 | Average / 1 | 9.90 | | |
| Hawaii | Hawaii Electric Light Co | D-2015-0170 | Electric | Vertically Integrated | 6/29/2018 | 9.50 | Average / 2 | | 9.50 | |
| New Mexico | Southwestern Public Service Co | C-17-00255-UT | Electric | Vertically Integrated | 9/5/2018 | 9.56 | Below Average / 2 | | | 9.56 |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-121 (Elec) | Electric | Vertically Integrated | 9/14/2018 | 10.00 | Above Average / 2 | 10.00 | | |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-122 (Elec) | Electric | Vertically Integrated | 9/20/2018 | 9.80 | Above Average / 2 | 9.80 | | |
| North Dakota | Otter Tail Power Co. | C-PU-17-398 | Electric | Vertically Integrated | 9/26/2018 | 9.77 | Average / 1 | 9.77 | | |
| Kansas | Westar Energy Inc. | D-18-WSEE-328-RTS | Electric | Vertically Integrated | 9/27/2018 | 9.30 | Below Average / 1 | | | 9.30 |
| Indiana | Indianapolis Power & Light Co. | Ca-45029 | Electric | Vertically Integrated | 10/31/2018 | 9.99 | Average / 1 | 9.99 | | |
| Kansas | Kansas City Power & Light | D-18-KCPE-480-RTS | Electric | Vertically Integrated | 12/13/2018 | 9.30 | Below Average / 1 | | | 9.30 |
| Oregon | Portland General Electric Co. | D-UE-335 | Electric | Vertically Integrated | 12/14/2018 | 9.50 | Average / 2 | | 9.50 | |
| Michigan | Consumers Energy Co. | C-U-20134 | Electric | Vertically Integrated | 1/9/2019 | 10.00 | Above Average / 3 | 10.00 | | |
| West Virginia | Appalachian Power Co. | C-18-0646-E-42T | Electric | Vertically Integrated | 2/27/2019 | 9.75 | Below Average / 2 | | | 9.75 |
| Oklahoma | Public Service Co. of OK | Ca-PUD201800097 | Electric | Vertically Integrated | 3/14/2019 | 9.40 | Average / 3 | | | 9.40 |
| Kentucky | Kentucky Utilities Co. | C-2018-00294 | Electric | Vertically Integrated | 4/30/2019 | 9.73 | Average / 1 | 9.73 | | |
| Kentucky | Louisville Gas & Electric Co. | C-2018-00295 (elec.) | Electric | Vertically Integrated | 4/30/2019 | 9.73 | Average / 1 | 9.73 | | |
| South Carolina | Duke Energy Carolinas LLC | D-2018-319-E | Electric | Vertically Integrated | 5/1/2019 | 9.50 | Average / 3 | | | 9.50 |
| Michigan | DTE Electric Co. | C-U-20162 | Electric | Vertically Integrated | 5/2/2019 | 10.00 | Above Average / 3 | 10.00 | | |
| South Carolina | Duke Energy Progress LLC | D-2018-318-E | Electric | Vertically Integrated | 5/8/2019 | 9.50 | Average / 3 | | | 9.50 |
| South Dakota | Otter Tail Power Co. | D-EL18-021 | Electric | Vertically Integrated | 5/14/2019 | 8.75 | Average / 2 | | 8.75 | |
| Hawaii | Maui Electric Company Ltd | D-2017-0150 | Electric | Vertically Integrated | 5/16/2019 | 9.50 | Average / 2 | | 9.50 | |
| Michigan | Upper Peninsula Power Co. | C-U-20276 | Electric | Vertically Integrated | 5/23/2019 | 9.90 | Above Average / 3 | 9.90 | | |
| Vermont | Green Mountain Power Corp. | C-19-1932-TF | Electric | Vertically Integrated | 8/29/2019 | 9.06 | Average / 3 | | | 9.06 |
| Wisconsin | Northern States Power Co - WI | D- 4220-UR-124 (Elec) | Electric | Vertically Integrated | 9/4/2019 | 10.00 | Above Average / 2 | 10.00 | | |
| Montana | NorthWestern Corp. | D2018.2.12 | Electric | Vertically Integrated | 12/20/2019 | 9.65 | Below Average / 1 | | | 9.65 |
| Wisconsin | Wisconsin Electric Power Co. | D-05-UR-109 (WEP-Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | Above Average / 2 | 10.00 | | |
| Wisconsin | Wisconsin Public Service Corp. | D-6690-UR-126 (Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | Above Average / 2 | 10.00 | | |
| Louisiana - NOCC | Entergy New Orleans LLC | D-UD-18-07 (elec.) | Electric | Vertically Integrated | 11/7/2019 | 9.35 | Average / 2 | | 9.35 | |
| Idaho | Avista Corp. | C-AVU-E-1904 | Electric | Vertically Integrated | 11/29/2019 | 9.50 | Average / 2 | | 9.50 | |
| Indiana | Northern IN Public Svc Co. | Ca-45159 | Electric | Vertically Integrated | 12/4/2019 | 9.75 | Average / 1 | 9.75 | | |
| Georgia | Georgia Power Co. | D-42516 | Electric | Vertically Integrated | 12/17/2019 | 10.50 | Above Average / 2 | 10.50 | | |
| California | San Diego Gas & Electric Co. | A-19-04-017 (Elec) | Electric | Vertically Integrated | 12/19/2019 | 10.20 | Average / 2 | | 10.20 | |
| California | Pacific Gas and Electric Co. | A-19-04-015 | Electric | Vertically Integrated | 12/19/2019 | 10.25 | Average / 2 | | 10.25 | |
| California | Southern California Edison Co. | A-19-04-014 | Electric | Vertically Integrated | 12/19/2019 | 10.30 | Average / 2 | | 10.30 | |
| Arkansas | Southwestern Electric Power Co | D-19-008-U | Electric | Vertically Integrated | 12/20/2019 | 9.45 | Average / 1 | 9.45 | | |
| Montana | NorthWestern Corp. | D2018.2.12 | Electric | Vertically Integrated | 12/20/2019 | 9.65 | Below Average / 1 | | | 9.65 |
| Nevada | Sierra Pacific Power Co. | D-19-06002 | Electric | Vertically Integrated | 12/24/2019 | 9.50 | Average / 2 | | 9.50 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|
| Iowa | Interstate Power & Light Co. | D-RPU-2019-0001 | Electric | Vertically Integrated | 1/8/2020 | 10.02 | Average / 1 | 10.02 | | |
| Michigan | Indiana Michigan Power Co. | C-U-20359 | Electric | Vertically Integrated | 1/23/2020 | 9.86 | Above Average / 3 | 9.86 | | |
| California | PacifiCorp | A-18-04-002 | Electric | Vertically Integrated | 2/6/2020 | 10.00 | Average / 2 | | 10.00 | |
| Colorado | Public Service Co. of CO | D-19AL-0268E | Electric | Vertically Integrated | 2/11/2020 | 9.30 | Average / 2 | | 9.30 | |
| North Carolina | Virginia Electric & Power Co. | E-22, Sub 562 | Electric | Vertically Integrated | 2/24/2020 | 9.75 | Average / 1 | 9.75 | | |
| Indiana | Indiana Michigan Power Co. | Ca-45235 | Electric | Vertically Integrated | 3/11/2020 | 9.70 | Average / 1 | 9.70 | | |
| Washington | Avista Corp. | D-UE-190334 | Electric | Vertically Integrated | 3/25/2020 | 9.40 | Average / 3 | | | 9.40 |
| | | | | | Total Cases | 103 | | 49 | 24 | 25 |
| | | | | | Mean | 9.75 | | 9.93 | 9.53 | 9.62 |
| | | | | | Median | 9.73 | | 9.95 | 9.50 | 9.50 |
| | | | | | Maximum | 11.95 | | 10.55 | 10.30 | 11.95 |
| | | | | | Minimum | 8.75 | | 9.37 | 8.75 | 9.06 |
| | | | | | 2019 Mean | 9.73 | | | | |
| | | | | | 2019 Median | 9.73 | | | | |

Source: Regulatory Research Associates

Steven G. De May
Stipulated Exhibits from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

STATE OF NORTH CAROLINA

COUNTY OF MECKLENBURG

IN THE GENERAL COURT OF JUSTICE
SUPERIOR COURT DIVISION
17-CVS- 5594



DUKE ENERGY CAROLINAS, LLC,

DUKE ENERGY PROGRESS, LLC,

Plaintiffs,

v.

AG INSURANCE SA/NV (f/k/a/L'Etoile S.A. Belge d'Assurances),

AGEAS INSURANCE LIMITED (f/k/a Bishopsgate Insurance Company Limited),

AIG PROPERTY CASUALTY COMPANY (f/k/a Birmingham Fire Insurance Company of Pennsylvania),

ALLEANZA ASSICURAZIONI S.P.A. (as successor to Lloyd Italico Assicurazioni S.p.A.),

ALLIANZ FRANCE S.A. (f/k/a Assurances Generales de France),

ALLIANZ GLOBAL RISKS US INSURANCE COMPANY (f/k/a Allianz Insurance Company),

ALLIANZ UNDERWRITERS INSURANCE COMPANY (f/k/a Allianz Underwriters, Inc.),

ALLSTATE INSURANCE COMPANY (as successor to Northbrook Insurance Company),

AMERICAN HOME ASSURANCE COMPANY,

ARROWOOD INDEMNITY COMPANY (f/k/a Royal Indemnity Company),

ASEGURADORA INTERACCIONES S.A. (f/k/a Seguros La Republica S.A.),

**COMPLAINT**

**JURY TRIAL DEMANDED**

ASSOCIATED ELECTRIC & GAS INSURANCE SERVICES LTD., )

AXA BELGIUM (as successor to Groupe Josi Compagnie Centrale d'Assurances), )

BERKSHIRE HATHAWAY DIRECT INSURANCE COMPANY (f/k/a American Centennial Insurance Company), )

CENTRE INSURANCE COMPANY (f/k/a London Guarantee and Accident Company of New York), )

CENTURY INDEMNITY COMPANY (as successor to California Union Insurance Company), )

COLUMBIA CASUALTY COMPANY, )

EMPLOYERS MUTUAL CASUALTY COMPANY, )

FEDERAL INSURANCE COMPANY, )

FIREMAN'S FUND INSURANCE COMPANY, )

FIRST STATE INSURANCE COMPANY, )

GENERAL REINSURANCE CORPORATION (as successor to North Star Reinsurance Corporation), )

GENERALI IARD S.A. (as successor to Le Continent), )

LEXINGTON INSURANCE COMPANY, )

OLD REPUBLIC INSURANCE COMPANY, )

PACIFIC EMPLOYERS INSURANCE COMPANY, )

SEGUROS DE RIESGOS LABORALES SURAMERICANA S.A. (as successor to Compania Agricola de Seguros), ) TIG INSURANCE COMPANY (as successor to Ranger Insurance Company and International Surplus Lines Insurance Company), )

TWIN CITY FIRE INSURANCE COMPANY, )

UNITED STATES FIRE INSURANCE COMPANY, )

Defendants. )

Plaintiffs Duke Energy Carolinas, LLC ("Duke Energy Carolinas") and Duke Energy Progress, LLC ("Duke Energy Progress") (collectively referred to herein as "Duke"), by their undersigned counsel, bring this action against the Defendant insurers identified below and, in support thereof, allege as follows:

## NATURE OF THE ACTION

1. This is a civil action seeking insurance coverage under certain third-party liability insurance policies ("the Policies") sold to Duke by the Defendant insurance companies. Each of the Policies provides coverage for liability for property damage caused by an occurrence.

2. In particular, Duke seeks damages for breach of contract and an order declaring the present and future rights, duties, and liabilities of the parties under the Policies and directing the Defendant insurers to indemnify Duke for damages suffered by Duke from certain environmental claims ("the Environmental Claims") asserted against Duke arising out of coal combustion residuals ("CCRs") at 14 Duke power plants in North Carolina and one Duke power plant in South Carolina.

## THE PARTIES

The Plaintiffs

3. **Duke Energy Carolinas**. Plaintiff Duke Energy Carolinas is a limited liability company organized under the laws of North Carolina and has its principal place of business in North Carolina. Duke Energy Carolinas was previously known as Duke Power Company ("Duke Power"). Duke Energy Carolinas is a legal entity under the law with the capacity to file suit.

4. **Duke Energy Progress**. Plaintiff Duke Energy Progress is a limited liability company organized under the laws of North Carolina and has its principal place of business in North Carolina. Duke Energy Progress was previously known as Carolina Power & Light Company ("Carolina Power & Light"). Duke Energy Progress is a legal entity under the law with the capacity to file suit.

The Defendants

5. **AG Insurance**. Upon information and belief, Defendant AG Insurance SA/NV, formerly known as L'Etoile S.A. Belge d'Assurances, is incorporated in Belgium and has its principal place of business in Belgium.

6. **Ageas Insurance Limited**. Upon information and belief, Defendant Ageas Insurance Limited, formerly known as Bishopsgate Insurance Company Limited, is incorporated in the United Kingdom and has its principal place of business in the United Kingdom.

7. **AIG Property Casualty Company**. Upon information and belief, Defendant AIG Property Casualty Company, formerly known as Birmingham Fire Insurance Company of Pennsylvania, is incorporated in Pennsylvania and has its principal place of business in New York.

8. **Alleanza Assicurazioni**. Upon information and belief, Defendant Alleanza Assicurazioni S.p.A., as successor to Lloyd Italico Assicurazioni S.p.A., is incorporated in Italy and has its principal place of business in Italy.

9. **Allianz France**. Upon information and belief, Defendant Allianz France S.A., formerly known as Assurances Generales de France, is incorporated in France and has its principal place of business in France.

10. **Allianz Global Risks**. Upon information and belief, Defendant Allianz Global Risks US Insurance Company, formerly known as Allianz Insurance Company, is incorporated in Illinois and has its principal place of business in Illinois.

11. **Allianz Underwriters**. Upon information and belief, Defendant Allianz Underwriters Insurance Company, formerly known as Allianz Underwriters, Inc., is incorporated in Illinois and has its principal place of business in Illinois.

12. **Allstate**. Upon information and belief, Defendant Allstate Insurance Company, as successor to Northbrook Insurance Company, is incorporated in Illinois and has its principal place of business in Illinois.

13. **American Home Assurance**. Upon information and belief, Defendant American Home Assurance Company is incorporated in New York and has its principal place of business in New York.

14. **Arrowood**. Upon information and belief, Defendant Arrowood Indemnity Company, formerly known as Royal Indemnity Company, is incorporated in Delaware and has its principal place of business in Charlotte, North Carolina.

15. **Aseguradora Interacciones**. Upon information and belief, Defendant Aseguradora Interacciones S.A., formerly known as Seguros La Republica S.A., is incorporated in Mexico and has its principal place of business in Mexico.

16. **AEGIS**. Upon information and belief, Defendant Associated Electric & Gas Insurance Services, Ltd. is incorporated in Bermuda and has its principal place of business in New Jersey.

17. **AXA Belgium**. Upon information and belief, Defendant AXA Belgium, as successor to Groupe Josi Compagnie Centrale d'Assurances, is incorporated in Belgium and has its principal place of business in Belgium.

18. **Berkshire Hathaway Direct**. Upon information and belief, Defendant Berkshire Hathaway Direct Insurance Company, formerly known as American Centennial Insurance Company, is incorporated in Nebraska and has its principal place of business in Nebraska.

19. **Centre**. Upon information and belief, Defendant Centre Insurance Company, formerly known as London Guarantee and Accident Company of New York, is incorporated in Delaware and has its principal place of business in New York.

20. **Century Indemnity**. Upon information and belief, Defendant Century Indemnity Company, as successor to California Union Insurance Company, is incorporated in Pennsylvania and has its principal place of business in Pennsylvania.

21. **Columbia**. Upon information and belief, Defendant Columbia Casualty Company is incorporated in Illinois and has its principal place of business in Illinois.

22. **Employers Mutual**. Upon information and belief, Defendant Employers Mutual Casualty Company is incorporated in Iowa and has its principal place of business in Iowa.

23. **Federal**. Upon information and belief, Defendant Federal Insurance Company is incorporated in Indiana and has its principal place of business in Pennsylvania.

24. **Fireman's Fund**. Upon information and belief, Defendant Fireman's Fund Insurance Company is incorporated in California and has its principal place of business in Illinois.

25. **First State**. Upon information and belief, Defendant First State Insurance Company is incorporated in Connecticut and has its principal place of business in Massachusetts.

26. **Gen Re**. Upon information and belief, Defendant General Reinsurance Corporation, as successor to North Star Reinsurance Corporation, is incorporated in Delaware and has its principal place of business in Connecticut.

27. **Generali IARD S.A.**. Upon information and belief, Defendant Generali IARD S.A., as successor to Le Continent, is incorporated in France and has its principal place of business in France.

28. **Lexington**. Upon information and belief, Defendant Lexington Insurance Company is incorporated in Delaware and has its principal place of business in Massachusetts.

29. **Old Republic**. Upon information and belief, Defendant Old Republic Insurance Company is incorporated in Pennsylvania and has its principal place of business in Pennsylvania.

30. **Pacific Employers**. Upon information and belief, Defendant Pacific Employers Insurance Company is incorporated in Pennsylvania and has its principal place of business in Pennsylvania.

31. **Seguros de Riesgos Laborales Suramericana S.A**. Upon information and belief, Defendant Seguros de Riesgos Laborales Suramericana S.A, as successor to Compania

Agricola de Seguros S.A., is incorporated in Colombia and has its principal place of business in Colombia.

32. **TIG**. Upon information and belief, Defendant TIG Insurance Company, as successor to Ranger Insurance Company and International Surplus Lines Insurance Company, is incorporated in California and has its principal place of business in New Hampshire.

33. **Twin City Fire**. Upon information and belief, Defendant Twin City Fire Insurance Company is incorporated in Indiana and has its principal place of business in Connecticut.

34. **U.S. Fire**. Upon information and belief, Defendant United States Fire Insurance Company is incorporated in Delaware and has its principal place of business in New Jersey.

## JURISDICTION AND VENUE

35. **Personal Jurisdiction**. This Court has personal jurisdiction over Defendants pursuant to applicable North Carolina law, at least because (i) the Defendants have engaged in substantial business activity within North Carolina, (ii) the insurance policies at issue in this action were issued to Plaintiffs in North Carolina, (iii) Plaintiffs were residents of North Carolina when the events out of which the claims in this action arose took place, (iv) the events out of which the claims in this action arose took place in North Carolina, and/or (v) the injurious consequences of Defendants' failure to comply with their contractual obligations to provide coverage have been endured by Plaintiffs in North Carolina. In addition, upon information and belief, Defendant Arrowood Indemnity Company's principal place of business is in North Carolina.

36. **Venue**. Venue in this Court is proper pursuant to N.C. Gen. Stat. § 1-80 and/or N.C. Gen. Stat. § 1-82.

## THE LIABILITY INSURANCE POLICIES

37. **Policies Sold to Duke Energy Carolinas**. From 1973 to 1986, Duke Power purchased excess-level third-party liability insurance with standard-form wording. The policy numbers and policy periods of those policies sold by Defendants that presently are known to Duke are set forth in Exhibit A to this Complaint, which is hereby incorporated by reference as if fully set forth herein. The policies are occurrence-based and remain in full force and effect.

38. **Policies Sold to Duke Energy Progress**. From 1971 to 1986, Carolina Power & Light purchased excess-level third-party liability insurance with standard-form wording. The policy numbers and policy periods of those policies sold by Defendants that presently are known to Duke are set forth in Exhibit B to this Complaint, which is hereby incorporated by reference as if fully set forth herein. The policies are occurrence-based and remain in full force and effect. The policies at issue sold by Defendants to Duke Power and Carolina Power & Light are collectively referred to herein as the "Policies."

39. **Duty to Indemnify**. The Policies each promise, with varying wording, to indemnify Duke for all sums Duke is legally obligated to pay on account of property damage caused by an occurrence, subject only to any underlying or upper limits of liability expressly and unambiguously stated in each respective Policy. The Policies also indemnify for fees and expenses incurred by Duke in the investigation and defense of any claim or suit. Duke's damages exceed the self-insured retentions and either reach or are expected to reach the level of attachment of all of the Policies.

## THE ENVIRONMENTAL CLAIMS

40. **Background.** Power plants that generate electricity through the combustion of coal create a number of waste byproducts. Among those waste byproducts are CCRs. CCRs

include fly ash, bottom ash, coal slag, and flue gas desulfurized gypsum. Fly ash and bottom ash are both commonly referred to as "coal ash." Coal ash contains various heavy metals and potentially hazardous constituents, including arsenic, barium, cadmium, chromium, lead, manganese, mercury, nitrates, sulfates, selenium, and thallium. Coal ash has not been defined, itself, as a "hazardous substance" or "hazardous waste" under federal law, although some constituents of coal ash may be hazardous in sufficient quantities or concentrations.

41. Coal ash basins (also known as "coal ash ponds," "coal ash impoundments," or "ash dikes") may be part of the waste treatment system at coal-fired power plants. Historically, Duke's coal ash basins were unlined earthen impoundments and typically operated as follows: Coal ash was mixed with water to form a slurry. The coal ash slurry was carried through sluice pipe lines to the coal ash basin. Settling occurred in the coal ash basin, in which particulate matter and free chemical components separated from the slurry and settled at the bottom of the basin. Less contaminated water remained at the surface of the basin, from which it eventually could be discharged if authorized under relevant law and permits. In some instances, water at the surface of the primary basin flowed into a secondary basin, where further settling and treatment occurred before its discharge into a water of the United States.

42. Coal ash basins generally continued to store settled ash and particulate material for years or decades. From time to time, Duke dredged settled coal ash from some of the basins, storing the ash in dry stacks on plant property.

43. Until recently, a total of approximately 108 million tons of coal ash was held in coal ash basins owned and operated by Duke in North Carolina. Duke also operates facilities with coal ash basins in South Carolina, where, until recently, there was approximately 6 million tons of coal ash.

44. It is alleged, without regard to historical awareness of harm, that coal ash constituents from coal ash basins and other areas have been infiltrating into groundwater over a long period of time. State environmental regulators have alleged that there have been environmental impacts or potential impacts to groundwater beneath each of Duke's North Carolina and South Carolina coal-fired power plants that are part of this claim.

45. Duke's CCR liability has evolved over time and continues to evolve. In North Carolina, Duke faces liability under the North Carolina Coal Ash Management Act ("CAMA"), which has undergone legal challenge and significant modification since it was first enacted and was significantly amended in July 2016. In both North Carolina and South Carolina, Duke also faces additional CCR liability under a recent United States Environmental Protection Agency ("EPA") rule regulating the disposal of CCRs ("CCR Rule"), as to which the scope of Duke's additional liability is not yet fully determined.

46. **North Carolina -- CAMA**. CAMA was the subject of substantial amendments in July 2016, pursuant to Session Law 2016-95. The amendments, among other things, clarify and cement Duke's remedial obligations and give the North Carolina Department of Environmental Quality ("NCDEQ") flexibility to update Duke's remedial obligations based on new information and changing conditions. The amendments introduced a number of new requirements and deadlines not contemplated in the original statute.

47. CAMA requires Duke to take investigatory and remedial steps in connection with CCRs at its North Carolina coal-fired power plants. CAMA requires an owner of a CCR surface impoundment to, *inter alia*, conduct groundwater monitoring and assessment to identify groundwater contamination, and to implement corrective action to restore groundwater quality in the event of groundwater contamination related to coal ash constituents. The remedial action

required under CAMA on account of groundwater and/or surface water contamination also includes source control, including the removal of CCRs from an impoundment or the construction of an impermeable environmental cap on top of an impoundment.

48. CAMA prescribes that the NCDEQ develop classifications for each North Carolina CCR surface impoundment based on the impoundment's risk to public health, safety, and welfare, the environment, and natural resources. Each impoundment is to be classified as high risk, intermediate risk, or low risk. In assessing a CCR impoundment's risk the NCDEQ considers three primary factors: impact to surface water, impact to groundwater, and structural integrity. CAMA requires that high and intermediate risk impoundments be dewatered and their CCRs be removed. CAMA requires that, at the election of NCDEQ, low risk impoundments be dewatered and covered with an impermeable environmental cap or that the CCRs be removed after dewatering. In May 2016, the NCDEQ released proposed classifications as to Duke's North Carolina power plants and designated all power plants – aside from those power plants specifically identified in CAMA, discussed below – as intermediate risk.

49. The North Carolina General Assembly expressly required by Session Laws 2014-122 and 2016-95 that Duke take certain remedial actions at certain specifically-identified power plants. By direct mandate of the North Carolina General Assembly, Duke must dewater and remove all CCRs from impoundments at the following seven power plants: Dan River Steam Station, Riverbend Steam Station, Asheville Steam Electric Generating Plant, L.V. Sutton Energy Complex, H.F. Lee Steam Electric Generating Plant, Cape Fear Steam Electric Generating Plant, and W.H. Weatherspoon Steam Electric Plant.

50. The July 2016 amendment made substantial changes to CAMA. It required Duke, as an additional remedial measure, to provide permanent water supplies to certain residences

near CCR impoundments that rely upon drinking water supply wells. The amendment provided that the NCDEQ shall classify a CCR impoundment as low risk if the impoundment owner provides a permanent water supply as required by the statute and other conditions are met. The amendment imposed an additional requirement that a certain amount of ash be beneficiated for cementitious purposes. The CCR impoundments at the Buck Steam Station and H.F. Lee Steam Electric Generating Plant are being excavated to comply with this CAMA obligation. In addition, pursuant to the July 2016 amendment, Duke must select a third ash beneficiation site by no later than July 1, 2017. The amendment also reflects the elimination of the Coal Ash Management Commission – the body originally charged with deciding impoundment classifications – after the Supreme Court of North Carolina ruled that the Commission was unconstitutional.

51. **Other North Carolina CCR Liability**. In addition to CAMA, Duke faces additional CCR-related liability at its North Carolina power plants on account of alleged environmental property damage under the federal CCR Rule. The CCR Rule establishes minimum criteria for the management and disposal of CCRs in landfills and impoundments and provides comprehensive guidance regarding risks imposed by, among other things, groundwater contamination. The CCR Rule requires groundwater monitoring and assessment to identify potential groundwater contamination. In the event contamination is identified, the CCR Rule may require remedial action including, but not limited to, corrective action to restore groundwater quality and source control, including the removal of CCRs from an impoundment or the construction of an impermeable environmental cap on top of an impoundment. Duke's potential liability for remedial action under the CCR Rule remains uncertain at this time, as the

deadline to begin evaluating the groundwater monitoring data for statistically significant increases over background levels for constituents is not until October 2017.

52. **The North Carolina Power Plants**. The North Carolina power plants at which Duke faces liability on account of alleged environmental property damage allegedly caused by CCRs are as follows:

Allen Steam Station

53. The Allen Steam Station, located in Belmont, Gaston County, North Carolina, commenced operation in 1957. The Allen plant is adjacent to the Catawba River. The Allen plant has been owned and operated since its inception by Duke Energy Carolinas.

54. Historically, CCRs generated at the Allen plant were managed primarily in on-site impoundments at the plant. There are two impoundments at the Allen plant: the Active Ash Basin and the Inactive Ash Basin.

55. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Allen plant for which Duke makes a claim under the Policies issued to Duke Power. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Asheville Steam Electric Generating Plant

56. The Asheville Steam Electric Generating Plant, located in Arden, Buncombe County, North Carolina, commenced operation in 1964. The Asheville plant is adjacent to the French Broad River and Lake Julian. The Asheville plant has been owned and operated since its inception by Duke Energy Progress.

57. Historically, CCRs generated at the Asheville plant were managed primarily in on-site impoundments at the plant. There are two impoundments at the Asheville plant: the 1964 Ash Basin and the 1982 Ash Basin.

58. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Asheville plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Belews Creek Steam Station

59. The Belews Creek Steam Station, located in Belews Creek, Stokes County, North Carolina, commenced operation in 1974. The Belews Creek plant is adjacent to West Belews Creek/Belews Lake. The Belews Creek plant has been owned and operated since its inception by Duke Energy Carolinas.

60. Historically, CCRs generated at the Belews Creek plant were managed primarily in an on-site impoundment at the plant. There is one CCR impoundment at the Belews Creek plant: the Active Ash Basin.

61. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Belews Creek plant for which Duke makes a claim under the Policies issued to Duke Power. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Buck Steam Station

62. The Buck Steam Station, located in Salisbury, Rowan County, North Carolina, commenced operation in 1926. The Buck plant is adjacent to the Yadkin River. The Buck plant has been owned and operated since its inception by Duke Energy Carolinas.

63. Historically, CCRs generated at the Buck plant were managed primarily in on-site impoundments at the plant. There are three CCR impoundments at the Buck plant: Ash Basin Cell 1, Ash Basin Cell 2, and Ash Basin Cell 3.

64. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Buck plant for which Duke makes a claim under the Policies issued to Duke Power. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Cape Fear Steam Electric Generating Plant

65. The Cape Fear Steam Electric Generating Plant, located in Moncure, Chatham County, North Carolina, commenced operation in 1923. The Cape Fear plant is adjacent to the Cape Fear River, Haw River, and Deep River. The Cape Fear plant has been owned and operated since its inception by Duke Energy Progress.

66. Historically, CCRs generated at the Cape Fear plant were managed primarily in on-site impoundments at the plant. There are five CCR impoundments at the Cape Fear plant: the 1956 Ash Pond, the 1963 Ash Pond, the 1970 Ash Pond, the 1978 Ash Pond, and the 1985 Ash Pond.

67. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the

Cape Fear plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Rogers Energy Complex (Cliffside Steam Station)

68. The Rogers Energy Complex (Cliffside Steam Station), located in Mooresboro, Rutherford and Cleveland Counties, North Carolina, commenced operation in 1940. The Cliffside plant is adjacent to the Broad River. The Cliffside plant has been owned and operated since its inception by Duke Energy Carolinas, formerly known as Duke Power.

69. Historically, CCRs generated at the Cliffside plant were managed primarily in on-site impoundments at the plant. There are three CCR impoundments at the Cliffside plant: the Active Ash Basin, Retired Unit 5 Basin, and Retired Unit 1-4 Basin.

70. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Cliffside plant for which Duke makes a claim under the Policies issued to Duke Power. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Dan River Steam Station

71. The Dan River Steam Station, located in Eden, Rockingham County, North Carolina, commenced operation in 1949. The Dan River plant is adjacent to the Dan River. The Dan River plant has been owned and operated since its inception by Duke Energy Carolinas.

72. Historically, CCRs generated at the Dan River plant were managed primarily in on-site impoundments at the plant. There are two CCR impoundments at the Dan River plant: the Primary Basin and the Secondary Basin.

73. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Dan River plant for which Duke makes a claim under the Policies issued to Duke Power. These costs do not include costs relating to the February 2, 2014, spill and cleanup of the Dan River. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

H.F. Lee Steam Electric Generating Plant

74. The H.F. Lee Steam Electric Generating Plant, located in Goldsboro, Wayne County, North Carolina, commenced operation in 1951. The H.F. Lee plant is adjacent to the Neuse River. The H.F. Lee plant has been owned and operated since its inception by Duke Energy Progress.

75. Historically, CCRs generated at the H.F. Lee plant were managed primarily in on-site impoundments at the plant. There are four CCR impoundments at the H.F. Lee plant: the Active Ash Pond, Ash Pond #1, Ash Pond #2, and Ash Pond #3.

76. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the H.F. Lee plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Marshall Steam Station

77. The Marshall Steam Station, located in Terrell, Catawba County, North Carolina, commenced operation in 1965. The Marshall plant is adjacent to Lake Norman. The Marshall plant has been owned and operated since its inception by Duke Energy Carolinas.

78. Historically, CCRs generated at the Marshall plant were managed primarily in an on-site impoundment at the plant. There is one CCR impoundment at the Marshall plant: the Ash Basin.

79. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Marshall plant for which Duke makes a claim under the Policies issued to Duke Power. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Mayo Steam Electric Generating Plant

80. The Mayo Steam Electric Generating Plant, located near Roxboro, Person County, North Carolina, commenced operation in 1983. The Mayo plant is adjacent to Mayo Lake and Crutchfield Branch. The Mayo plant has been owned and operated since its inception by Duke Energy Progress.

81. Historically, CCRs generated at the Mayo plant were managed primarily in an on-site impoundment at the plant. There is one CCR impoundment at the Mayo plant: the Ash Pond.

82. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Mayo plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Riverbend Steam Station

83. The Riverbend Steam Station, located in Mount Holly, Gaston County, North Carolina, commenced operation in 1929. The Riverbend plant is adjacent to the Catawba River (Mountain Island Lake). The Riverbend plant has been owned and operated since its inception by Duke Energy Carolinas.

84. Historically, CCRs generated at the Riverbend plant were managed primarily in on-site impoundments at the plant. There are two CCR impoundments at the Riverbend plant: the Primary Basin and the Secondary Basin.

85. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Riverbend plant for which Duke makes a claim under the Policies issued to Duke Power. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

Roxboro Steam Electric Generating Plant

86. The Roxboro Steam Electric Generating Plant, located near Semora, Person County, North Carolina, commenced operation in 1966. The Roxboro plant is adjacent to Hyco Lake. The Roxboro plant has been owned and operated since its inception by Duke Energy Progress.

87. Historically, CCRs generated at the Roxboro plant were managed primarily in on-site impoundments at the plant. There are two CCR impoundments at the Roxboro plant: the East Ash Pond and the West Ash Pond.

88. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the

Roxboro plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

L.V. Sutton Energy Complex

89. The L.V. Sutton Energy Complex, located in Wilmington, New Hanover County, North Carolina, commenced operation in 1954. The Sutton plant is adjacent to the Cape Fear River. The Sutton plant has been owned and operated since its inception by Duke Energy Progress.

90. Historically, CCRs generated at the Sutton plant were managed primarily in on-site impoundments at the plant. There are two CCR impoundments at the Sutton plant: the 1971 Ash Basin and the 1984 Ash Basin.

91. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Sutton plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

W.H. Weatherspoon Steam Electric Plant

92. The W.H. Weatherspoon Steam Electric Plant, located near Lumberton, Robeson County, North Carolina, commenced operation in 1949. The Weatherspoon plant is adjacent to the Lumber River. The Weatherspoon plant has been owned and operated since its inception by Duke Energy Progress.

93. Historically, CCRs generated at the Weatherspoon plant were managed primarily in an on-site impoundment at the plant. There is one CCR impoundment at the Weatherspoon plant: the Ash Pond.

94. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Weatherspoon plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

95. **The South Carolina Power Plant**. The South Carolina power plant at which Duke faces liability on account of alleged environmental property damage allegedly caused by CCRs is as follows:

H.B. Robinson Steam Electric Plant

96. The H.B. Robinson Steam Electric Plant, located near Hartsville, Darlington County, South Carolina, commenced operation in 1960. The Robinson plant is adjacent to Lake Robinson. The Robinson plant has been owned and operated since its inception by Duke Energy Progress.

97. Historically, CCRs generated at the Robinson plant were managed primarily in an on-site impoundment at the plant. There is one CCR impoundment at the Robinson plant.

98. The South Carolina Department of Health and Environmental Control ("SCDHEC") issued a Notice of Violation to Duke in which it alleged that the CCR impoundment at the Robinson plant caused groundwater contamination, and, as a result, SCDHEC ordered Duke to investigate and remediate groundwater.

99. Duke is obligated to and will conduct groundwater remediation at the Robinson plant. Due to site-specific factors, source control will be accomplished through the excavation of CCRs from the CCR impoundment. CCRs removed from the impoundment will be moved to a lined, permitted landfill that Duke will construct on-site.

100. Duke has incurred substantial costs on account of its liability for alleged CCR-related environmental property damage arising out of impoundments and/or other areas at the Robinson plant for which Duke makes a claim under the Policies issued to Carolina Power & Light. Duke is incurring substantial additional costs on an ongoing basis and will continue to incur substantial additional costs in the future.

101. In addition, Duke may face additional CCR-related liability at the Robinson plant on account of alleged environmental property damage under the federal CCR Rule. As with Duke's North Carolina power plants, Duke's potential liability at the Robinson plant for remedial action under the CCR Rule remains uncertain at this time, as groundwater monitoring is ongoing.

## COVERAGE UNDER THE POLICIES

102. **Coverage**. The Policies provide coverage for Duke's CCR liability. Duke satisfies the requirements for coverage in each Policy. Duke faces liability on account of, and is being legally compelled to investigate and remediate, alleged environmental property damage allegedly caused by CCRs at the North and South Carolina power plants identified above. The alleged environmental property damage includes damage to third party property, including groundwater, that is not owned by Duke. Duke's liability for alleged property damage is caused by an occurrence during the policy period of each of the Policies.

103. The costs Duke has incurred and/or will incur on account of alleged environmental property damage at each of the above-referenced power plants will exceed the available per-occurrence limits of each of the Policies.

104. Duke has complied with all conditions and paid all premiums. No Policy exclusions apply. Duke is entitled to the full benefits and protections of the Policies.

105. **The Defendant Insurers' Failure to Provide Coverage.** Duke notified Defendants of its specific CCR liability at each of the North Carolina and South Carolina power plants described in Paragraphs 52 to 101, and asserted a specific claim against each Defendant under the Policies demanding coverage.

106. No Defendant has honored its contractual obligation to provide coverage for the Environmental Claims. Defendants have reserved rights or refused to respond to Duke's request for coverage. The Defendant insurers have breached and/or repudiated their contractual obligations under the Policies.

## CAUSES OF ACTION

### Count I – Breach of Contract

107. **Incorporation by Reference.** Duke repeats and incorporates by reference the allegations in the preceding paragraphs as if fully set forth herein.

108. **Entitlement to Benefits of the Policies.** The Policies are valid and enforceable contracts under which Defendants agreed to provide insurance coverage pursuant to the Policies' terms. Pursuant to the Policies' terms, Defendants are required to provide coverage in connection with Duke's CCR liability at the North Carolina and South Carolina power plants identified above.

109. **Assertion of Claim**. Duke asserted that Defendants are responsible to indemnify it for damages arising out of the Environmental Claims.

110. **Breach**. Defendants breached their contractual obligations under the Policies by repudiating their coverage obligations and/or otherwise failing to provide coverage or respond to Duke's request for coverage.

111. As a direct and proximate result of the Defendants' respective breaches of the Policies, Duke has incurred damages currently recoverable under the Policies and will continue to incur substantial additional sums, damages, and expenses. Defendants' breaches have caused Duke actual damages, including the payment of millions of dollars for environmental response costs in connection with CCR claims against it. Defendants have deprived Duke of the benefit of the insurance coverage each Defendant agreed to provide and for which each Defendant has been paid premiums.

**Count II – Declaratory Judgment**

112. **Incorporation by Reference**. Duke repeats and incorporates by reference the allegations in the preceding paragraphs as if fully set forth herein.

113. **Entitlement to Benefits of the Policies**. The Policies are valid and enforceable contracts under which Defendants agreed to provide insurance coverage pursuant to the Policies' terms. Pursuant to the Policies' terms, Defendants are required to provide coverage in connection with Duke's CCR liability at the North Carolina and South Carolina power plants identified above.

114. **Disputed Coverage**. Upon receipt of notice of the Environmental Claims, Defendants have failed to honor their contractual obligations under the Policies and Duke is

informed and believes that Defendants dispute their obligation to indemnify Duke under the Policies in connection with the Environmental Claims.

115. **Actual Controversy**. An actual and justiciable controversy presently exists between Duke and Defendants with respect to Defendants' duties and obligations under the Policies in connection with Duke's CCR liability described herein. The controversy is of sufficient immediacy to justify the issuance of a declaratory judgment. The issuance of declaratory relief by this Court will terminate some or all of the existing controversy between the parties. Duke is entitled to a declaration that Defendants are required under the terms of their Policies to provide coverage to Duke for damages and costs Duke will incur on account of its CCR liability described herein.

116. **Necessity of Declaratory Relief**. The rights, status, and other legal relations between Duke and Defendants are uncertain and insecure. Continuing uncertainty regarding the extent of available insurance will perpetuate and augment the injury Duke already is suffering, including: (i) an increased financial burden on itself and its ratepayers, which Defendants promised to bear, and (ii) the burden of interfacing with enforcement agencies in the face of continuing uncertainty as to the total financial exposure and sources of funding to meet current CCR liabilities. The entry of a declaratory judgment by this Court is necessary to terminate the uncertainty and controversy giving rise to this proceeding.

**PRAYER FOR RELIEF**

117. WHEREFORE, Duke respectfully requests that this Court enter a judgment as follows:

a. On Count I, order that Defendants pay compensatory and consequential damages in an amount to be determined at trial for Duke's damages, sums, costs, expenses, "loss," and "ultimate net loss" incurred on account of its CCR liability at the North Carolina and South Carolina power plants described herein;

b. On Count II, issue a declaration that Duke is entitled to coverage under the Policies with respect to its CCR liability described herein, and that Defendants are obligated to provide coverage under the terms of their Policies for Duke's future damages, sums, costs, expenses, "loss," and "ultimate net loss" incurred on account of its CCR liability;

c. Order that Defendants pay prejudgment and post-judgment interest and Duke's costs, expenses, and attorneys' fees incurred in connection with this action;

d. An award of such other and further relief as the Court deems just and proper.

**DEMAND FOR JURY TRIAL**

Plaintiffs Duke Energy Carolinas and Duke Energy Progress demand a trial by jury on all issues so triable.

This the 29th day of March, 2017.

Respectfully submitted,

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*Counsel for Plaintiffs Duke Energy Carolinas and Duke Energy Progress*

## EXHIBIT A

### Policies Issued to Duke Power
### (By Original Insurer Name)

| Insurer | Policy Number | Policy Period Start | Policy Period End |
|---|---|---|---|
| Allianz Insurance Company | XL559537 | 10/31/1982 | 10/31/1983 |
| Allianz Underwriters, Inc. | AUX 5200514 | 10/31/1981 | 10/31/1982 |
| American Centennial Insurance Company | CC 002611 | 10/31/1981 | 10/31/1983 |
| Associated Electric and Gas Insurance Services Ltd. | 172 | 12/31/1979 | 12/31/1980 |
| Associated Electric and Gas Insurance Services Ltd. | 209CNJ | 10/31/1985 | 10/31/1986 |
| California Union Insurance Company | UT 3569 | 12/31/1979 | 12/31/1980 |
| California Union Insurance Company | ZCX 006009 | 10/31/1981 | 10/31/1982 |
| California Union Insurance Company | ZCX 007450 | 10/31/1984 | 10/31/1985 |
| Certain London Market and Other Companies* | K25801 | 10/23/1973 | 12/31/1975 |
| Certain London Market and Other Companies* | UGL 1330 | 12/31/1975 | 12/31/1976 |
| Certain London Market and Other Companies* | UGL 1331 | 12/31/1975 | 12/31/1978 |
| Certain London Market and Other Companies* | UGL 1332 | 12/31/1975 | 12/31/1978 |
| Certain London Market and Other Companies* | UGL 1333 | 12/31/1975 | 12/31/1978 |
| Certain London Market and Other Companies* | UHL 1370 | 12/31/1976 | 12/31/1977 |
| Certain London Market and Other Companies* | UJL 1680 | 12/31/1977 | 12/31/1978 |
| Columbia Casualty Company | UT 3569 | 12/31/1979 | 12/31/1980 |
| Employers Mutual Casualty Company | 20021 | 12/31/1978 | 12/31/1979 |
| Federal Insurance Company | (85) 7929-31-72 | 10/31/1984 | 10/31/1985 |
| Fireman's Fund Insurance Company | XLX 1531024 | 10/31/1983 | 10/31/1984 |
| Fireman's Fund Insurance Company | XLX 1687008 | 10/31/1984 | 10/31/1985 |
| Fireman's Fund Insurance Company | XLX 1687003 | 11/9/1984 | 10/31/1985 |
| First State Insurance Company | 127720 | 10/23/1973 | 1/31/1976 |
| First State Insurance Company | 130224 | 2/1/1978 | 12/31/1978 |
| First State Insurance Company | UT 3569 | 12/31/1979 | 12/31/1980 |
| First State Insurance Company | 929871 | 10/31/1981 | 10/31/1982 |
| First State Insurance Company | 917316 | 10/31/1982 | 10/31/1983 |
| International Surplus Lines Insurance Company | UT 3569 | 12/31/1979 | 12/31/1980 |
| London Guarantee and Accident Company | LX3278836 | 10/31/1981 | 10/31/1982 |

| | | | |
|---|---|---|---|
| of New York | | | |
| London Guarantee and Accident Company of New York | LX1898119 | 10/31/1982 | 10/31/1983 |
| North Star Reinsurance Corporation | NSX-11822 | 10/23/1973 | 12/31/1976 |
| Northbrook Insurance Company | 127719/63 000 264 | 10/23/1973 | 12/31/1975 |
| Old Republic Insurance Company | OZX-11486 | 10/31/1981 | 10/31/1982 |
| Pacific Employers Insurance Company | XCC 002383 | 10/31/1982 | 10/31/1983 |
| Ranger Insurance Company | BSP 122047 | 10/31/1981 | 10/31/1983 |
| Ranger Insurance Company | EUL 300658 | 10/31/1983 | 10/31/1984 |
| Ranger Insurance Company | EUL 300579 | 10/31/1984 | 10/31/1985 |
| Royal Indemnity Company | EC103320 | 10/31/1984 | 10/31/1985 |
| Twin City Fire Insurance Company | TXS101193 | 10/31/1982 | 10/31/1983 |

*The following insurers subscribed to one or more of the above-referenced policies issued in the London insurance market to Duke Power Company: American Centennial Insurance Company; Assurances Generales de France; Bishopsgate Insurance Company Limited; Compania Agricola de Seguros S.A.; Groupe Josi Compagnie Centrale d'Assurances; Le Continent; Seguros La Republica S.A.

## EXHIBIT B

### Policies Issued to Carolina Power & Light (By Original Insurer Name)

| Insurer | Policy Number | Policy Period Start | Policy Period End |
|---|---|---|---|
| American Centennial Insurance Company | CC 002613 | 10/31/1981 | 10/31/1983 |
| Associated Electric and Gas Insurance Services Ltd. | 211CNJ | 10/31/1985 | 10/31/1986 |
| Certain London Market and Other Companies^ | K24880 | 12/31/1971 | 12/31/1972 |
| Certain London Market and Other Companies^ | K25800 | 12/31/1972 | 12/31/1975 |
| Certain London Market and Other Companies^ | K25801 | 8/9/1973 | 12/31/1975 |
| Certain London Market and Other Companies^ | UGL 1330 | 12/31/1975 | 12/31/1976 |
| Certain London Market and Other Companies^ | UGL 1331 | 12/31/1975 | 12/31/1978 |
| Certain London Market and Other Companies^ | UGL 1332 | 12/31/1975 | 12/31/1978 |
| Certain London Market and Other Companies^ | UGL 1333 | 12/31/1975 | 12/31/1978 |
| Certain London Market and Other Companies^ | UHL 1370 | 12/31/1976 | 12/31/1977 |
| Certain London Market and Other Companies^ | UJL 1680 | 12/31/1977 | 12/31/1978 |
| Federal Insurance Company | (85) 7929-31-63 | 10/31/1984 | 10/31/1985 |
| Fireman's Fund Insurance Company | XLX 1530917 | 10/31/1983 | 10/31/1984 |
| Pacific Employers Insurance Company | XCC 002380 | 10/31/1982 | 10/31/1983 |
| Pacific Employers Insurance Company | XCC 012437 | 10/31/1983 | 10/31/1984 |
| Ranger Insurance Company | BSP 122048 | 10/31/1981 | 10/31/1983 |
| Ranger Insurance Company | EUL 300659 | 10/31/1983 | 10/31/1984 |
| Ranger Insurance Company | EUL 300578 | 10/31/1984 | 10/31/1985 |
| United States Fire Insurance Company | 522 020271 6 | 10/31/1984 | 10/31/1985 |

^The following insurers subscribed to one or more of the above-referenced policies issued in the London insurance market to Carolina Power & Light Company: American Home Assurance Company; Birmingham Fire Insurance Company of Pennsylvania; Compania Agricola de Seguros S.A.; L'Etoile S.A. Belge d'Assurances; Le Continent; Lexington Insurance Company; Lloyd Italico Assicurazioni S.p.A.; Seguros La Republica S.A.

# Duke Energy Progress
## Docket No. E-2 SUB 1219
### Storm Costs Recovery Total
### Jackson Exhibit 1, Page 1 of 1

| Line No. | Description | REF. | (A) Storm Costs ($000's) |
|---|---|---|---|
| 1 | **Total Storm Costs (2018)** | | |
| 2 | Florence | RSJ-2 p1 line 16 column H | $453,694 |
| 3 | Michael | RSJ-2 p2 line 16 column H | 30,840 |
| 4 | Diego | RSJ-2 p3 line 16 column H | 30,650 |
| 5 | Dorian | RSJ-2 p4 line 16 column H | 204,372 |
| 6 | **Total Recoverable Restoration Costs** | lines 4:6 | $719,556 |
| 7 | | | |
| 8 | **Total Capital Costs** | RSJ-2 p1-4 line 18 column H | $114,484 |

I/A



# Duke Energy Progress
## Docket No. E-2 SUB 1219
## Storm Costs by Storm - Florence
## Jackson Exhibit 2, Page 1 of 4

| | | | (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|---|---|---|
| | | | **Storm Costs By Function ($000's)** | | | | |
| **Line No.** | **Description** | **REF.** | **Distribution** | **Transmission** | **Customer Operations** | **Generation** | **Total** |
| 1 | **Storm Related Restoration Costs** | | | | | | |
| 2 | Company Labor | | 25,183 | 8,239 | 140 | 1,918 | 35,480 |
| 3 | Contract Labor | | 388,868 | 33,355 | 9 | 1,675 | 423,907 |
| 4 | Veg Management Contract Labor | | 24,401 | 3,886 | - | - | 28,288 |
| 5 | Fleet | | 371 | 326 | - | - | 697 |
| 6 | Materials | | 16,203 | 1,426 | 3 | 230 | 17,863 |
| 7 | Other | | (34,093) | 1,167 | 4,336 | 1,031 | (27,558) |
| 8 | **Subtotal - Storm Related Restoration Costs** | lines 2:7 | **420,932** | **48,399** | **4,489** | **4,854** | **478,675** |
| 9 | | | | | | | |
| 10 | **Less: Estimated Non-Incremental Costs** | | | | | | |
| 11 | Company Labor | | (5,460) | (5,222) | - | - | (10,682) |
| 12 | Fleet | | (94) | (250) | - | - | (344) |
| 13 | Other | | (12,427) | (1,528) | - | | (13,955) |
| 14 | **Subtotal - Estimated Non-Incremental Costs** | lines 11:13 | **(17,981)** | **(7,000)** | **-** | **-** | **(24,981)** |
| 15 | | | | | | | |
| 16 | **Total Recoverable Restoration Costs** | lines (8 + 14) | **402,952** | **41,399** | **4,489** | **4,854** | **453,694** |
| 17 | | | | | | | |
| 18 | **Capital Costs** | | **71,300** | **12,700** | **-** | **-** | **84,000** |

# Duke Energy Progress
## Docket No. E-2 SUB 1219
## Storm Costs by Storm - Michael
## Jackson Exhibit 2, Page 2 of 4

| | | | (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|---|---|---|
| | | | Storm Costs By Function ($000's) | | | | |
| **Line No.** | **Description** | **REF.** | **Distribution** | **Transmission** | **Customer Operations** | **Generation** | **Total** |
| 1 | **Storm Related Restoration Costs** | | | | | | |
| 2 | Company Labor | | 3,473 | 282 | 245 | - | 3,999 |
| 3 | Contract Labor | | 29,201 | 102 | 115 | - | 29,418 |
| 4 | Veg Management labor | | 2,276 | 504 | - | - | 2,780 |
| 5 | Fleet | | 32 | 27 | - | - | 59 |
| 6 | Materials | | 2,773 | 50 | 210 | - | 3,033 |
| 7 | Other | | (6,337) | 30 | 138 | - | (6,169) |
| 8 | **Subtotal - Storm Related Restoration Costs** | lines 2:7 | **31,419** | **994** | **708** | **-** | **33,121** |
| 9 | | | | | | | |
| 10 | **Less: Estimated Non-Incremental Costs** | | | | | | |
| 11 | Company Labor | | (1,463) | (193) | - | - | (1,656) |
| 12 | Fleet | | (31) | (26) | - | - | (57) |
| 13 | Other | | (567) | | - | | (567) |
| 14 | **Subtotal - Estimated Non-Incremental Costs** | lines 11:13 | **(2,062)** | **(219)** | **-** | **-** | **(2,281)** |
| 15 | | | | | | | |
| 16 | **Total Recoverable Restoration Costs** | lines (8 + 14) | **29,357** | **775** | **708** | **-** | **30,840** |
| 17 | | | | | | | |
| 18 | **Capital Costs** | | **9,300** | | **-** | **-** | **9,300** |

I/A





**Duke Energy Progress**
**Docket No. E-2 SUB 1219**
**Storm Costs by Storm - Diego**
**Jackson Exhibit 2, Page 3 of 4**

| Line No. | Description | REF. | (A) Distribution | (B) Transmission | (C) Customer Operations | (D) Generation | (E) Total |
|---|---|---|---|---|---|---|---|
| | | | Storm Costs By Function ($000's) | | | | |
| 1 | **Storm Related Restoration Costs** | | | | | | |
| 2 | Company Labor | | 1,858 | 80 | - | - | 1,938 |
| 3 | Contract Labor | | 28,165 | 156 | - | - | 28,321 |
| 4 | Veg Management labor | | 1,060 | 28 | - | - | 1,088 |
| 5 | Fleet | | 12 | 12 | - | - | 24 |
| 6 | Materials | | 583 | 16 | - | - | 599 |
| 7 | Other | | 603 | 13 | - | - | 615 |
| 8 | **Subtotal - Storm Related Restoration Costs** | lines 2:7 | **32,280** | **305** | **-** | **-** | **32,585** |
| 9 | | | | | | | |
| 10 | **Less: Estimated Non-Incremental Costs** | | | | | | |
| 11 | Company Labor | | (936) | (60) | - | - | (996) |
| 12 | Fleet | | (10) | (12) | - | - | (22) |
| 13 | Other | | (917) | - | - | | (917) |
| 14 | **Subtotal - Estimated Non-Incremental Costs** | lines 11:13 | **(1,863)** | **(73)** | **-** | **-** | **(1,935)** |
| 15 | | | | | | | |
| 16 | **Total Recoverable Restoration Costs** | lines (8 + 14) | **30,417** | **232** | **-** | **-** | **30,650** |
| 17 | | | | | | | |
| 18 | **Capital Costs** | | **1,511** | **-** | **-** | **-** | **1,511** |

I/A



**Duke Energy Progress**
**Docket No. E-2 SUB 1219**
**Storm Costs by Storm - Dorian**
**Jackson Exhibit 2, Page 4 of 4**

*Details by cost driver to be provided at a later date.*

| | | | (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|---|---|---|
| | | | Storm Costs By Function ($000's) | | | | |
| Line No. | Description | REF. | Distribution | Transmission | Customer Operations | Generation | Total |
| 1 | **Storm Related Restoration Costs** | | | | | | |
| 2 | Company Labor | | - | - | - | - | - |
| 3 | Contract Labor | | - | - | - | - | - |
| 4 | Veg Management labor | | - | - | - | - | - |
| 5 | Fleet | | - | - | - | - | - |
| 6 | Materials | | - | - | - | - | - |
| 7 | Other | | - | - | - | - | - |
| 8 | **Subtotal - Storm Related Restoration Costs** | lines 2:7 | **188,000** | **30,000** | **1,872** | **-** | **219,872** |
| 9 | | | | | | | |
| 10 | **Less: Estimated Non-Incremental Costs** | | | | | | |
| 11 | Company Labor | | - | - | - | - | - |
| 12 | Fleet | | - | - | - | - | - |
| 13 | Other | | - | - | - | - | - |
| 14 | **Subtotal - Estimated Non-Incremental Costs** | lines 11:13 | **(14,000)** | **(1,500)** | **-** | **-** | **(15,500)** |
| 15 | | | | | | | |
| 16 | **Total Recoverable Restoration Costs** | lines (8 + 14) | **174,000** | **28,500** | **1,872** | **-** | **204,372** |
| 17 | | | | | | | |
| 18 | **Capital Costs** | | **19,673** | **-** | **-** | **-** | **19,673** |

**Docket E-2. Sub 1219**

MCGEE EXHIBIT 1


## DUKE ENERGY PROGRESS, LLC
## North Carolina Retail Fuel and Fuel-Related Rates Proposed for Base Rate Case

| Line No. | Class | Prospective Rate (cents/kWh) |
|---|---|---|
| | | (a) |
| 1 | Residential | 2.311 |
| 2 | Small General Service | 2.556 |
| 3 | Medium General Service | 2.477 |
| 4 | Large General Service | 1.757 |
| 5 | Lighting | 2.251 |

Notes:
(a) Prospective Rates were taken directly from Appendix A of the Order Approving Fuel Charge Adjustment in E-2, Sub 1173

**Docket E-2. Sub 1219**

MCGEE EXHIBIT 1
Page 2 of 2

**DUKE ENERGY PROGRESS, LLC**
**North Carolina Retail Adjusted Fuel and Fuel-Related Costs**
**Twelve Months Ended December 31, 2018**

| Line No. | Description | Residential (Col. 1) | SGS (a) (Col. 2) | MGS (a) (Col. 3) | LGS (Col. 4) | Lighting (Col. 5) | NC Retail (Col. 6) | Note |
|---|---|---|---|---|---|---|---|---|
| 1 | NC retail sales per books (kWh) | 16,666,046,589 | 1,982,596,401 | 11,222,040,191 | 8,457,791,022 | 358,793,310 | 38,687,267,513 | |
| 2 | Weather adjustment (kWh) | (546,076,604) | (189,478,942) | (20,347,830) | (12,137,502) | - | (768,040,877) | ( b ) |
| 3 | Customer growth adjustment (kWh) | (82,972,645) | 10,625,959 | 158,639,942 | 33,272,037 | (479,677) | 119,085,616 | ( c ) |
| 4 | NC retail sales, adjusted (lines 1+2+3) (kWh) | 16,036,997,340 | 1,803,743,418 | 11,360,332,303 | 8,478,925,557 | 358,313,633 | 38,038,312,252 | |
| 5 | System fuel and fuel-related costs factors per kWh (¢/kWh) | 2.311 | 2.556 | 2.477 | 1.757 | 2.251 | | ( d ) |
| 6 | Total NC retail fuel and fuel-related costs ((line 4 * line 5) /100) | $370,615,009 | $46,103,682 | $281,395,431 | $148,974,722 | $8,065,640 | $ 855,154,483 | |

Notes:
( a ) For fuel purposes, SGS-TOU and SI are included in the MGS class
( b ) Weather Adjustment, from proforma NC-0301, Line 6
( c ) Customer Growth Adjustment, from proforma NC-0402, Col. (a)
( d ) McGee Exhibit 1, page 1 of 2

**Docket E-2 Sub 1219**

MCGEE SUPPLEMENTAL EXHIBIT 1


## DUKE ENERGY PROGRESS, LLC
## North Carolina Retail Fuel and Fuel-Related Rates Proposed for Base Rate Case

| Line No. | Class | Prospective Rate (cents/kWh) |
|---|---|---|
| | | (a) |
| 1 | Residential | 2.326 |
| 2 | Small General Service | 2.499 |
| 3 | Medium General Service | 2.456 |
| 4 | Large General Service | 2.054 |
| 5 | Lighting | 2.217 |

Notes:
(a) Prospective Rates were taken directly from Appendix A of the Order Approving Fuel Charge Adjustment in E-2, Sub 1204

**Docket E-2 Sub 1219**

MCGEE SUPPLEMENTAL EXHIBIT 1
Page 2 of 2

**DUKE ENERGY PROGRESS, LLC**
**North Carolina Retail Adjusted Fuel and Fuel-Related Costs**
**Twelve Months Ended December 31, 2018**

| Line No. | Description | Residential (Col. 1) | SGS (a) (Col. 2) | MGS (a) (Col. 3) | LGS (Col. 4) | Lighting (Col. 5) | NC Retail (Col. 6) | Note |
|---|---|---|---|---|---|---|---|---|
| 1 | NC retail sales per books (kWh) | 16,666,046,589 | 1,982,596,401 | 11,222,040,191 | 8,457,791,022 | 358,793,310 | 38,687,267,513 | |
| 2 | Weather adjustment (kWh) | (628,587,507) | (34,426,443) | (162,787,434) | (46,375,228) | - | (872,176,612) | ( b ) |
| 3 | Customer growth adjustment (kWh) | 57,867,175 | (51,924,021) | (150,689,187) | 56,502,116 | 963,841 | (87,280,077) | ( c ) |
| 4 | NC retail sales, adjusted (lines 1+2+3) (kWh) | 16,095,326,257 | 1,896,245,937 | 10,908,563,570 | 8,467,917,910 | 359,757,151 | 37,727,810,825 | |
| 5 | System fuel and fuel-related costs factors per kWh (¢/kWh) | 2.326 | 2.499 | 2.456 | 2.054 | 2.217 | | ( d ) |
| 6 | Total NC retail fuel and fuel-related costs ((line 4 * line 5) /100) | $374,377,289 | $47,387,186 | $267,914,321 | $173,931,034 | $7,975,816 | $ 871,585,646 | |

Notes:
( a ) For fuel purposes, SGS-TOU and SI are included in the MGS class
( b ) Weather Adjustment, from proforma NC-0301, Supplemental E, Line 1
( c ) Customer Growth Adjustment, from proforma NC-0401, Supplemental E, Line 5
( d ) McGee Exhibit 1, page 1 of 2

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $61.34 | 4.03% | 4.15% | NA | 7.00% | 5.50% | 6.25% | 9.64% | 10.40% | 11.17% |
| Alliant Energy Corporation | LNT | $1.52 | $49.05 | 3.10% | 3.19% | 5.50% | 5.65% | 6.50% | 5.88% | 8.68% | 9.07% | 9.70% |
| Ameren Corporation | AEE | $1.98 | $73.95 | 2.68% | 2.75% | 5.90% | 4.90% | 6.00% | 5.60% | 7.64% | 8.35% | 8.76% |
| American Electric Power Company, Inc. | AEP | $2.80 | $82.61 | 3.39% | 3.49% | 5.80% | 6.15% | 5.00% | 5.65% | 8.47% | 9.14% | 9.64% |
| Avangrid, Inc. | AGR | $1.76 | $44.42 | 3.96% | 4.11% | 6.80% | 6.30% | 8.50% | 7.20% | 10.39% | 11.31% | 12.63% |
| Avista Corporation | AVA | $1.62 | $43.56 | 3.72% | 3.81% | 5.40% | 6.10% | 3.50% | 5.00% | 7.28% | 8.81% | 9.93% |
| CMS Energy Corporation | CMS | $1.63 | $59.21 | 2.75% | 2.85% | 7.10% | 7.50% | 7.50% | 7.37% | 9.95% | 10.22% | 10.36% |
| DTE Energy Company | DTE | $4.05 | $96.10 | 4.21% | 4.33% | 6.00% | 6.00% | 5.00% | 5.67% | 9.32% | 10.00% | 10.34% |
| Evergy, Inc | EVRG | $2.02 | $57.44 | 3.52% | 3.59% | 5.00% | 3.90% | NMF | 4.45% | 7.49% | 8.04% | 8.60% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $42.72 | 3.09% | 3.14% | 3.50% | 3.30% | 2.50% | 3.10% | 5.63% | 6.24% | 6.64% |
| NextEra Energy, Inc. | NEE | $5.60 | $228.30 | 2.45% | 2.56% | 7.60% | 7.59% | 10.00% | 8.40% | 10.14% | 10.95% | 12.58% |
| NorthWestern Corporation | NWE | $2.40 | $60.71 | 3.95% | 4.01% | 3.30% | 3.79% | 2.00% | 3.03% | 5.99% | 7.04% | 7.82% |
| OGE Energy Corp. | OGE | $1.55 | $30.64 | 5.06% | 5.14% | 3.40% | 1.70% | 4.50% | 3.20% | 6.80% | 8.34% | 9.67% |
| Otter Tail Corporation | OTTR | $1.48 | $43.20 | 3.43% | 3.55% | NA | 9.00% | 5.00% | 7.00% | 8.51% | 10.55% | 12.58% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $77.40 | 4.04% | 4.13% | 4.40% | 4.62% | 4.00% | 4.34% | 8.12% | 8.47% | 8.76% |
| PNM Resources, Inc. | PNM | $1.23 | $39.99 | 3.08% | 3.17% | 5.90% | 6.30% | 7.00% | 6.40% | 9.07% | 9.57% | 10.18% |
| Portland General Electric Company | POR | $1.54 | $48.75 | 3.16% | 3.23% | 4.70% | 4.70% | 4.50% | 4.63% | 7.73% | 7.87% | 7.93% |
| Southern Company | SO | $2.48 | $54.86 | 4.52% | 4.60% | 4.00% | 2.10% | 4.00% | 3.37% | 6.67% | 7.96% | 8.61% |
| WEC Energy Group, Inc. | WEC | $2.53 | $92.21 | 2.74% | 2.83% | 6.20% | 6.23% | 6.00% | 6.14% | 8.83% | 8.97% | 9.06% |
| Xcel Energy Inc. | XEL | $1.72 | $61.55 | 2.79% | 2.88% | 6.00% | 6.10% | 5.50% | 5.87% | 8.37% | 8.74% | 8.98% |
| Proxy Group Mean | | | | 3.48% | 3.58% | 5.36% | 5.45% | 5.39% | 5.43% | 8.24% | 9.00% | 9.70% |
| Proxy Group Median | | | | 3.41% | 3.52% | 5.65% | 6.05% | 5.00% | 5.66% | 8.42% | 8.89% | 9.66% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of April 17, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $74.17 | 3.33% | 3.43% | NA | 7.00% | 5.50% | 6.25% | 8.92% | 9.68% | 10.45% |
| Alliant Energy Corporation | LNT | $1.52 | $53.94 | 2.82% | 2.90% | 5.50% | 5.65% | 6.50% | 5.88% | 8.40% | 8.78% | 9.41% |
| Ameren Corporation | AEE | $1.98 | $78.00 | 2.54% | 2.61% | 5.90% | 4.90% | 6.00% | 5.60% | 7.50% | 8.21% | 8.61% |
| American Electric Power Company, Inc. | AEP | $2.80 | $92.55 | 3.03% | 3.11% | 5.80% | 6.15% | 5.00% | 5.65% | 8.10% | 8.76% | 9.27% |
| Avangrid, Inc. | AGR | $1.76 | $49.41 | 3.56% | 3.69% | 6.80% | 6.30% | 8.50% | 7.20% | 9.97% | 10.89% | 12.21% |
| Avista | AVA | $1.62 | $47.39 | 3.42% | 3.50% | 5.40% | 6.10% | 3.50% | 5.00% | 6.98% | 8.50% | 9.62% |
| CMS Energy Corporation | CMS | $1.63 | $63.06 | 2.58% | 2.68% | 7.10% | 7.50% | 7.50% | 7.37% | 9.78% | 10.05% | 10.18% |
| DTE Energy Company | DTE | $4.05 | $118.20 | 3.43% | 3.52% | 6.00% | 6.00% | 5.00% | 5.67% | 8.51% | 9.19% | 9.53% |
| Evergy, Inc | EVRG | $2.02 | $64.35 | 3.14% | 3.21% | 5.00% | 3.90% | NMF | 4.45% | 7.10% | 7.66% | 8.22% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $45.68 | 2.89% | 2.93% | 3.50% | 3.30% | 2.50% | 3.10% | 5.43% | 6.03% | 6.44% |
| NextEra Energy, Inc. | NEE | $5.60 | $246.91 | 2.27% | 2.36% | 7.60% | 7.59% | 10.00% | 8.40% | 9.94% | 10.76% | 12.38% |
| NorthWestern Corporation | NWE | $2.40 | $69.83 | 3.44% | 3.49% | 3.30% | 3.79% | 2.00% | 3.03% | 5.47% | 6.52% | 7.29% |
| OGE Energy Corp. | OGE | $1.55 | $39.69 | 3.90% | 3.97% | 3.40% | 1.70% | 4.50% | 3.20% | 5.64% | 7.17% | 8.49% |
| Otter Tail Corporation | OTTR | $1.48 | $49.38 | 3.00% | 3.10% | NA | 9.00% | 5.00% | 7.00% | 8.07% | 10.10% | 12.13% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $88.33 | 3.54% | 3.62% | 4.40% | 4.62% | 4.00% | 4.34% | 7.61% | 7.96% | 8.25% |
| PNM Resources, Inc. | PNM | $1.23 | $47.94 | 2.57% | 2.65% | 5.90% | 6.30% | 7.00% | 6.40% | 8.54% | 9.05% | 9.66% |
| Portland General Electric Company | POR | $1.54 | $55.12 | 2.79% | 2.86% | 4.70% | 4.70% | 4.50% | 4.63% | 7.36% | 7.49% | 7.56% |
| Southern Company | SO | $2.48 | $62.17 | 3.99% | 4.06% | 4.00% | 2.10% | 4.00% | 3.37% | 6.13% | 7.42% | 8.07% |
| WEC Energy Group, Inc. | WEC | $2.53 | $94.83 | 2.67% | 2.75% | 6.20% | 6.23% | 6.00% | 6.14% | 8.75% | 8.89% | 8.98% |
| Xcel Energy Inc. | XEL | $1.72 | $64.44 | 2.67% | 2.75% | 6.00% | 6.10% | 5.50% | 5.87% | 8.24% | 8.61% | 8.85% |
| Proxy Group Mean | | | | 3.08% | 3.16% | 5.36% | 5.45% | 5.39% | 5.43% | 7.82% | 8.59% | 9.28% |
| Proxy Group Median | | | | 3.01% | 3.11% | 5.65% | 6.05% | 5.00% | 5.66% | 8.09% | 8.69% | 9.12% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of April 17, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

| Company | Ticker | [1] Annualized Dividend | [2] Average Stock Price | [3] Dividend Yield | [4] Expected Dividend Yield | [5] Zacks Earnings Growth | [6] First Call Earnings Growth | [7] Value Line Earnings Growth | [8] Average Earnings Growth | [9] Low ROE | [10] Mean ROE | [11] High ROE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | $2.47 | $79.42 | 3.11% | 3.21% | NA | 7.00% | 5.50% | 6.25% | 8.70% | 9.46% | 10.22% |
| Alliant Energy Corporation | LNT | $1.52 | $53.24 | 2.86% | 2.94% | 5.50% | 5.65% | 6.50% | 5.88% | 8.43% | 8.82% | 9.45% |
| Ameren Corporation | AEE | $1.98 | $77.25 | 2.56% | 2.63% | 5.90% | 4.90% | 6.00% | 5.60% | 7.53% | 8.23% | 8.64% |
| American Electric Power Company, Inc. | AEP | $2.80 | $92.13 | 3.04% | 3.13% | 5.80% | 6.15% | 5.00% | 5.65% | 8.12% | 8.78% | 9.28% |
| Avangrid, Inc. | AGR | $1.76 | $49.69 | 3.54% | 3.67% | 6.80% | 6.30% | 8.50% | 7.20% | 9.95% | 10.87% | 12.19% |
| Avista | AVA | $1.62 | $47.33 | 3.42% | 3.51% | 5.40% | 6.10% | 3.50% | 5.00% | 6.98% | 8.51% | 9.63% |
| CMS Energy Corporation | CMS | $1.63 | $62.61 | 2.60% | 2.70% | 7.10% | 7.50% | 7.50% | 7.37% | 9.80% | 10.07% | 10.20% |
| DTE Energy Company | DTE | $4.05 | $123.14 | 3.29% | 3.38% | 6.00% | 6.00% | 5.00% | 5.67% | 8.37% | 9.05% | 9.39% |
| Evergy, Inc | EVRG | $2.02 | $64.23 | 3.14% | 3.21% | 5.00% | 3.90% | NMF | 4.45% | 7.11% | 7.66% | 8.22% |
| Hawaiian Electric Industries, Inc. | HE | $1.32 | $45.06 | 2.93% | 2.97% | 3.50% | 3.30% | 2.50% | 3.10% | 5.47% | 6.07% | 6.48% |
| NextEra Energy, Inc. | NEE | $5.60 | $236.68 | 2.37% | 2.47% | 7.60% | 7.59% | 10.00% | 8.40% | 10.05% | 10.86% | 12.48% |
| NorthWestern Corporation | NWE | $2.40 | $71.02 | 3.38% | 3.43% | 3.30% | 3.79% | 2.00% | 3.03% | 5.41% | 6.46% | 7.23% |
| OGE Energy Corp. | OGE | $1.55 | $41.46 | 3.74% | 3.80% | 3.40% | 1.70% | 4.50% | 3.20% | 5.47% | 7.00% | 8.32% |
| Otter Tail Corporation | OTTR | $1.48 | $50.78 | 2.91% | 3.02% | NA | 9.00% | 5.00% | 7.00% | 7.99% | 10.02% | 12.05% |
| Pinnacle West Capital Corporation | PNW | $3.13 | $90.47 | 3.46% | 3.53% | 4.40% | 4.62% | 4.00% | 4.34% | 7.53% | 7.87% | 8.16% |
| PNM Resources, Inc. | PNM | $1.23 | $49.16 | 2.50% | 2.58% | 5.90% | 6.30% | 7.00% | 6.40% | 8.48% | 8.98% | 9.59% |
| Portland General Electric Company | POR | $1.54 | $55.56 | 2.77% | 2.84% | 4.70% | 4.70% | 4.50% | 4.63% | 7.33% | 7.47% | 7.54% |
| Southern Company | SO | $2.48 | $61.34 | 4.04% | 4.11% | 4.00% | 2.10% | 4.00% | 3.37% | 6.19% | 7.48% | 8.12% |
| WEC Energy Group, Inc. | WEC | $2.53 | $93.29 | 2.71% | 2.80% | 6.20% | 6.23% | 6.00% | 6.14% | 8.79% | 8.94% | 9.03% |
| Xcel Energy Inc. | XEL | $1.72 | $63.61 | 2.70% | 2.78% | 6.00% | 6.10% | 5.50% | 5.87% | 8.28% | 8.65% | 8.89% |
| Proxy Group Mean | | | | 3.05% | 3.14% | 5.36% | 5.45% | 5.39% | 5.43% | 7.80% | 8.56% | 9.26% |
| Proxy Group Median | | | | 2.98% | 3.07% | 5.65% | 6.05% | 5.00% | 5.66% | 8.05% | 8.71% | 9.15% |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of April 17, 2020
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 12.93% | 1.37% | 11.56% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 24,632.77 | N/A | 0.91% | N/A | N/A | N/A |
| American Airlines Group Inc | AAL | 4,929.50 | 0.02% | 2.59% | -12.30% | -9.87% | -0.0020% |
| Advance Auto Parts Inc | AAP | 8,211.97 | 0.03% | 0.63% | 11.15% | 11.82% | 0.0039% |
| Apple Inc | AAPL | 1,237,385.74 | 5.01% | 1.14% | 10.98% | 12.18% | 0.6096% |
| AbbVie Inc | ABBV | 123,228.35 | 0.50% | 5.77% | 1.53% | 7.35% | 0.0366% |
| AmerisourceBergen Corp | ABC | 18,363.49 | 0.07% | 1.87% | 12.35% | 14.33% | 0.0106% |
| ABIOMED Inc | ABMD | 7,481.30 | N/A | 0.00% | N/A | N/A | N/A |
| Abbott Laboratories | ABT | 169,307.23 | 0.69% | 1.48% | 8.10% | 9.64% | 0.0660% |
| Accenture PLC | ACN | 111,705.15 | 0.45% | 1.82% | 10.50% | 12.42% | 0.0561% |
| Adobe Inc | ADBE | 165,792.49 | 0.67% | 0.00% | 17.67% | 17.67% | 0.1185% |
| Analog Devices Inc | ADI | 37,853.03 | 0.15% | 2.33% | 12.15% | 14.63% | 0.0224% |
| Archer-Daniels-Midland Co | ADM | 20,722.56 | 0.08% | 3.89% | 8.80% | 12.86% | 0.0108% |
| Automatic Data Processing Inc | ADP | 60,911.89 | 0.25% | 2.48% | 16.00% | 18.68% | 0.0460% |
| Alliance Data Systems Corp | ADS | 1,803.18 | 0.01% | 23.67% | -0.40% | 23.22% | 0.0017% |
| Autodesk Inc | ADSK | 39,720.21 | 0.16% | 0.00% | 33.95% | 33.95% | 0.0546% |
| Ameren Corp | AEE | 19,203.56 | 0.08% | 2.60% | 6.45% | 9.13% | 0.0071% |
| American Electric Power Co Inc | AEP | 42,743.65 | 0.17% | 3.27% | 6.91% | 10.29% | 0.0178% |
| AES Corp/VA | AES | 8,721.76 | 0.04% | 4.45% | 7.81% | 12.43% | 0.0044% |
| Aflac Inc | AFL | 26,357.22 | 0.11% | 3.12% | 0.67% | 3.80% | 0.0041% |
| Allergan PLC | AGN | 61,523.38 | N/A | 1.60% | N/A | N/A | N/A |
| American International Group Inc | AIG | 21,101.61 | 0.09% | 5.31% | 15.85% | 21.58% | 0.0184% |
| Apartment Investment & Management Co | AIV | 5,830.63 | 0.02% | 4.21% | 2.35% | 6.61% | 0.0016% |
| Assurant Inc | AIZ | 6,329.95 | N/A | 2.40% | N/A | N/A | N/A |
| Arthur J Gallagher & Co | AJG | 15,851.19 | 0.06% | 2.14% | 10.44% | 12.69% | 0.0081% |
| Akamai Technologies Inc | AKAM | 17,054.25 | 0.07% | 0.00% | 11.80% | 11.80% | 0.0081% |
| Albemarle Corp | ALB | 6,535.41 | 0.03% | 2.47% | 8.00% | 10.57% | 0.0028% |
| Align Technology Inc | ALGN | 15,200.43 | 0.06% | 0.00% | 21.00% | 21.00% | 0.0129% |
| Alaska Air Group Inc | ALK | 3,668.96 | 0.01% | 1.23% | -14.87% | -13.73% | -0.0020% |
| Allstate Corp/The | ALL | 33,197.25 | 0.13% | 2.00% | 7.37% | 9.45% | 0.0127% |
| Allegion plc | ALLE | 9,003.27 | 0.04% | 1.06% | 3.01% | 4.09% | 0.0015% |
| Alexion Pharmaceuticals Inc | ALXN | 22,879.43 | 0.09% | 0.00% | 10.92% | 10.92% | 0.0101% |
| Applied Materials Inc | AMAT | 48,853.83 | 0.20% | 1.63% | 13.16% | 14.90% | 0.0294% |
| Amcor PLC | AMCR | 14,083.54 | 0.06% | 5.39% | 8.10% | 13.71% | 0.0078% |
| Advanced Micro Devices Inc | AMD | 66,270.24 | 0.27% | 0.00% | 20.33% | 20.33% | 0.0545% |
| AMETEK Inc | AME | 18,406.26 | 0.07% | 0.79% | 7.90% | 8.72% | 0.0065% |
| Amgen Inc | AMGN | 138,106.56 | 0.56% | 2.68% | 8.06% | 10.85% | 0.0606% |
| Ameriprise Financial Inc | AMP | 13,643.36 | 0.06% | 3.70% | 3.90% | 7.67% | 0.0042% |
| American Tower Corp | AMT | 112,663.38 | 0.46% | 1.78% | 16.80% | 18.72% | 0.0853% |
| Amazon.com Inc | AMZN | 1,183,996.93 | 4.79% | 0.00% | 34.85% | 34.85% | 1.6695% |
| Arista Networks Inc | ANET | 15,889.85 | 0.06% | 0.00% | 15.80% | 15.80% | 0.0102% |
| ANSYS Inc | ANSS | 22,584.66 | 0.09% | 0.00% | 11.50% | 11.50% | 0.0105% |
| Anthem Inc | ANTM | 67,527.40 | 0.27% | 1.42% | 12.76% | 14.27% | 0.0390% |
| Aon PLC | AON | 44,136.65 | 0.18% | 0.99% | 11.30% | 12.35% | 0.0220% |
| AO Smith Corp | AOS | 6,655.17 | 0.03% | 2.49% | 8.00% | 10.59% | 0.0029% |
| Apache Corp | APA | 3,204.28 | 0.01% | 3.89% | -18.00% | -14.46% | -0.0019% |
| Air Products & Chemicals Inc | APD | 48,880.28 | 0.20% | 2.31% | 11.35% | 13.80% | 0.0273% |
| Amphenol Corp | APH | 24,916.09 | 0.10% | 1.17% | 6.02% | 7.22% | 0.0073% |
| Aptiv PLC | APTV | 16,313.59 | 0.07% | 0.98% | 8.39% | 9.42% | 0.0062% |
| Alexandria Real Estate Equities Inc | ARE | 19,599.32 | 0.08% | 2.70% | 3.33% | 6.08% | 0.0048% |
| Atmos Energy Corp | ATO | 13,539.40 | 0.05% | 2.08% | 7.35% | 9.50% | 0.0052% |
| Activision Blizzard Inc | ATVI | 51,445.54 | 0.21% | 0.59% | 8.59% | 9.20% | 0.0192% |
| AvalonBay Communities Inc | AVB | 23,976.97 | 0.10% | 3.73% | 6.68% | 10.53% | 0.0102% |
| Broadcom Inc | AVGO | 106,296.52 | 0.43% | 4.89% | 5.40% | 10.42% | 0.0448% |
| Avery Dennison Corp | AVY | 9,109.25 | 0.04% | 2.16% | 7.00% | 9.24% | 0.0034% |
| American Water Works Co Inc | AWK | 23,851.14 | 0.10% | 1.62% | 8.19% | 9.88% | 0.0095% |
| American Express Co | AXP | 70,416.95 | 0.28% | 2.02% | 4.85% | 6.92% | 0.0197% |
| AutoZone Inc | AZO | 23,160.94 | 0.09% | 0.00% | 9.63% | 9.63% | 0.0090% |
| Boeing Co/The | BA | 86,890.78 | 0.35% | 1.33% | 12.90% | 14.32% | 0.0503% |
| Bank of America Corp | BAC | 201,965.35 | 0.82% | 3.18% | 9.25% | 12.58% | 0.1028% |
| Baxter International Inc | BAX | 47,144.81 | 0.19% | 1.01% | 11.95% | 13.02% | 0.0248% |
| Best Buy Co Inc | BBY | 18,128.24 | 0.07% | 3.21% | 7.00% | 10.33% | 0.0076% |
| Becton Dickinson and Co | BDX | 70,884.66 | 0.29% | 1.37% | 11.40% | 12.85% | 0.0369% |
| Franklin Resources Inc | BEN | 8,119.31 | 0.03% | 6.63% | -9.73% | -3.42% | -0.0011% |
| Brown-Forman Corp | BF/B | 29,746.50 | 0.12% | 1.06% | 2.77% | 3.84% | 0.0046% |
| Biogen Inc | BIIB | 59,625.63 | 0.24% | 0.00% | 0.16% | 0.16% | 0.0004% |
| Bank of New York Mellon Corp/The | BK | 33,106.71 | 0.13% | 3.35% | 4.15% | 7.57% | 0.0101% |
| Booking Holdings Inc | BKNG | 60,396.59 | 0.24% | 0.00% | 12.43% | 12.43% | 0.0304% |
| Baker Hughes Co | BKR | 13,436.13 | 0.05% | 5.55% | 16.89% | 22.91% | 0.0125% |
| BlackRock Inc | BLK | 74,024.18 | 0.30% | 3.04% | 3.84% | 6.95% | 0.0208% |
| Ball Corp | BLL | 22,870.21 | 0.09% | 0.77% | 8.53% | 9.34% | 0.0086% |
| Bristol-Myers Squibb Co | BMY | 137,105.28 | 0.55% | 2.97% | 11.38% | 14.52% | 0.0805% |
| Broadridge Financial Solutions Inc | BR | 12,621.39 | 0.05% | 1.98% | 7.10% | 9.15% | 0.0047% |
| Berkshire Hathaway Inc | BRK/B | 463,136.35 | 1.87% | 0.00% | -3.10% | -3.10% | -0.0581% |
| Boston Scientific Corp | BSX | 53,575.36 | 0.22% | 0.00% | 11.03% | 11.03% | 0.0239% |
| BorgWarner Inc | BWA | 5,576.88 | 0.02% | 2.59% | 9.38% | 12.10% | 0.0027% |
| Boston Properties Inc | BXP | 14,814.11 | 0.06% | 4.17% | 3.29% | 7.53% | 0.0045% |
| Citigroup Inc | C | 94,617.81 | 0.38% | 4.53% | -1.53% | 2.97% | 0.0114% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Conagra Brands Inc | CAG | 16,356.02 | 0.07% | 2.53% | 8.40% | 11.04% | 0.0073% |
| Cardinal Health Inc | CAH | 14,948.07 | 0.06% | 3.94% | 4.73% | 8.76% | 0.0053% |
| Carrier Global Corp | CARR | 11,901.02 | N/A | 0.00% | N/A | N/A | N/A |
| Caterpillar Inc | CAT | 63,974.61 | 0.26% | 3.68% | 7.83% | 11.66% | 0.0302% |
| Chubb Ltd | CB | 53,682.13 | 0.22% | 2.59% | 10.00% | 12.72% | 0.0276% |
| Cboe Global Markets Inc | CBOE | 11,191.42 | 0.05% | 1.46% | 10.00% | 11.53% | 0.0052% |
| CBRE Group Inc | CBRE | 14,960.66 | 0.06% | 0.00% | 8.45% | 8.45% | 0.0051% |
| Crown Castle International Corp | CCI | 69,618.00 | 0.28% | 2.92% | 16.00% | 19.15% | 0.0539% |
| Carnival Corp | CCL | 9,310.71 | 0.04% | 11.42% | -2.76% | 8.50% | 0.0032% |
| Cadence Design Systems Inc | CDNS | 22,087.53 | 0.09% | 0.00% | 9.84% | 9.84% | 0.0088% |
| CDW Corp/DE | CDW | 15,480.49 | 0.06% | 1.37% | 13.10% | 14.56% | 0.0091% |
| Celanese Corp | CE | 9,345.30 | 0.04% | 3.42% | 5.32% | 8.83% | 0.0033% |
| Cerner Corp | CERN | 21,300.24 | 0.09% | 0.64% | 14.47% | 15.15% | 0.0131% |
| CF Industries Holdings Inc | CF | 6,048.32 | 0.02% | 4.27% | 6.00% | 10.40% | 0.0025% |
| Citizens Financial Group Inc | CFG | 8,476.27 | 0.03% | 7.71% | -38.61% | -32.39% | -0.0111% |
| Church & Dwight Co Inc | CHD | 18,076.85 | 0.07% | 1.31% | 7.82% | 9.18% | 0.0067% |
| CH Robinson Worldwide Inc | CHRW | 9,749.35 | 0.04% | 2.79% | 10.00% | 12.93% | 0.0051% |
| Charter Communications Inc | CHTR | 132,774.53 | 0.54% | 0.00% | 24.58% | 24.58% | 0.1320% |
| Cigna Corp | CI | 72,200.73 | 0.29% | 0.03% | 11.02% | 11.05% | 0.0323% |
| Cincinnati Financial Corp | CINF | 13,920.70 | N/A | 3.00% | N/A | N/A | N/A |
| Colgate-Palmolive Co | CL | 62,953.78 | 0.25% | 2.48% | 5.24% | 7.78% | 0.0198% |
| Clorox Co/The | CLX | 24,206.77 | 0.10% | 2.18% | 4.40% | 6.63% | 0.0065% |
| Comerica Inc | CMA | 4,210.31 | 0.02% | 9.21% | -4.66% | 4.34% | 0.0007% |
| Comcast Corp | CMCSA | 173,379.56 | 0.70% | 2.41% | 8.78% | 11.29% | 0.0792% |
| CME Group Inc | CME | 68,691.86 | 0.28% | 3.25% | 8.27% | 11.65% | 0.0324% |
| Chipotle Mexican Grill Inc | CMG | 22,809.94 | 0.09% | 0.00% | 13.20% | 13.20% | 0.0122% |
| Cummins Inc | CMI | 22,096.89 | 0.09% | 3.55% | 0.31% | 3.87% | 0.0035% |
| CMS Energy Corp | CMS | 17,953.42 | 0.07% | 2.57% | 7.17% | 9.84% | 0.0071% |
| Centene Corp | CNC | 41,833.74 | 0.17% | 0.00% | 14.77% | 14.77% | 0.0250% |
| CenterPoint Energy Inc | CNP | 8,308.22 | 0.03% | 4.94% | -1.04% | 3.87% | 0.0013% |
| Capital One Financial Corp | COF | 24,988.93 | 0.10% | 2.98% | 7.17% | 10.26% | 0.0104% |
| Cabot Oil & Gas Corp | COG | 8,354.14 | 0.03% | 1.94% | 1.10% | 3.05% | 0.0010% |
| Cooper Cos Inc/The | COO | 16,334.05 | 0.07% | 0.02% | 8.93% | 8.95% | 0.0059% |
| ConocoPhillips | COP | 37,970.08 | 0.15% | 4.79% | -13.00% | -8.52% | -0.0131% |
| Costco Wholesale Corp | COST | 140,387.10 | 0.57% | 0.85% | 8.07% | 8.96% | 0.0509% |
| Coty Inc | COTY | 4,373.76 | 0.02% | 6.26% | 2.89% | 9.24% | 0.0016% |
| Campbell Soup Co | CPB | 15,189.82 | 0.06% | 2.80% | 7.48% | 10.38% | 0.0064% |
| Capri Holdings Ltd | CPRI | 1,931.29 | 0.01% | 0.00% | -0.89% | -0.89% | -0.0001% |
| Copart Inc | CPRT | 16,850.17 | N/A | 0.00% | N/A | N/A | N/A |
| salesforce.com Inc | CRM | 145,544.90 | 0.59% | 0.00% | 19.15% | 19.15% | 0.1128% |
| Cisco Systems Inc | CSCO | 180,152.59 | 0.73% | 3.33% | 5.42% | 8.84% | 0.0644% |
| CSX Corp | CSX | 48,377.54 | 0.20% | 1.62% | 10.48% | 12.19% | 0.0239% |
| Cintas Corp | CTAS | 21,242.89 | N/A | 1.25% | N/A | N/A | N/A |
| CenturyLink Inc | CTL | 11,253.48 | 0.05% | 9.76% | 0.63% | 10.42% | 0.0047% |
| Cognizant Technology Solutions Corp | CTSH | 29,522.16 | 0.12% | 1.61% | 10.38% | 12.07% | 0.0144% |
| Corteva Inc | CTVA | 19,114.22 | 0.08% | 1.96% | 11.58% | 13.65% | 0.0106% |
| Citrix Systems Inc | CTXS | 18,568.21 | 0.08% | 0.93% | 9.17% | 10.14% | 0.0076% |
| CVS Health Corp | CVS | 82,722.29 | 0.33% | 3.16% | 8.30% | 11.59% | 0.0388% |
| Chevron Corp | CVX | 162,744.53 | N/A | 5.85% | N/A | N/A | N/A |
| Concho Resources Inc | CXO | 10,216.96 | 0.04% | 1.53% | 4.60% | 6.16% | 0.0025% |
| Dominion Energy Inc | D | 68,327.64 | 0.28% | 4.64% | 4.90% | 9.65% | 0.0267% |
| Delta Air Lines Inc | DAL | 15,535.08 | 0.06% | 1.65% | -15.05% | -13.53% | -0.0085% |
| DuPont de Nemours Inc | DD | 28,148.37 | 0.11% | 3.21% | 2.22% | 5.46% | 0.0062% |
| Deere & Co | DE | 43,423.83 | 0.18% | 2.30% | 1.10% | 3.41% | 0.0060% |
| Discover Financial Services | DFS | 10,730.58 | 0.04% | 5.16% | 4.36% | 9.64% | 0.0042% |
| Dollar General Corp | DG | 45,803.41 | 0.19% | 0.78% | 10.53% | 11.35% | 0.0210% |
| Quest Diagnostics Inc | DGX | 12,755.09 | 0.05% | 2.37% | 5.60% | 8.03% | 0.0041% |
| DR Horton Inc | DHI | 14,610.59 | 0.06% | 1.72% | 10.45% | 12.26% | 0.0072% |
| Danaher Corp | DHR | 109,085.00 | 0.44% | 0.46% | 11.21% | 11.70% | 0.0516% |
| Walt Disney Co/The | DIS | 192,513.92 | 0.78% | 1.74% | 18.26% | 20.16% | 0.1570% |
| Discovery Inc | DISCA | 15,187.87 | 0.06% | 0.00% | -0.63% | -0.63% | -0.0004% |
| DISH Network Corp | DISH | 11,779.12 | 0.05% | 0.00% | -0.08% | -0.08% | 0.0000% |
| Digital Realty Trust Inc | DLR | 40,003.87 | 0.16% | 3.07% | 18.50% | 21.85% | 0.0354% |
| Dollar Tree Inc | DLTR | 19,354.55 | 0.08% | 0.00% | 8.45% | 8.45% | 0.0066% |
| Dover Corp | DOV | 12,749.99 | 0.05% | 2.27% | 10.70% | 13.09% | 0.0068% |
| Dow Inc | DOW | 24,820.36 | 0.10% | 8.54% | 3.33% | 12.01% | 0.0121% |
| Duke Realty Corp | DRE | 12,862.53 | 0.05% | 2.68% | 4.11% | 6.84% | 0.0036% |
| Darden Restaurants Inc | DRI | 7,654.17 | 0.03% | 4.05% | 6.89% | 11.07% | 0.0034% |
| DTE Energy Co | DTE | 20,334.32 | 0.08% | 3.84% | 6.03% | 9.98% | 0.0082% |
| Duke Energy Corp | DUK | 66,135.98 | 0.27% | 4.30% | 4.86% | 9.26% | 0.0248% |
| DaVita Inc | DVA | 9,816.90 | 0.04% | 0.00% | 15.18% | 15.18% | 0.0060% |
| Devon Energy Corp | DVN | 3,530.34 | 0.01% | 4.61% | 7.47% | 12.25% | 0.0018% |
| DXC Technology Co | DXC | 3,889.54 | 0.02% | 5.38% | -7.39% | -2.21% | -0.0003% |
| Electronic Arts Inc | EA | 33,356.00 | 0.13% | 0.00% | 8.09% | 8.09% | 0.0109% |
| eBay Inc | EBAY | 29,817.21 | 0.12% | 1.69% | 11.23% | 13.02% | 0.0157% |
| Ecolab Inc | ECL | 51,688.47 | 0.21% | 1.08% | 10.70% | 11.83% | 0.0247% |
| Consolidated Edison Inc | ED | 29,910.90 | 0.12% | 3.42% | 3.46% | 6.94% | 0.0084% |
| Equifax Inc | EFX | 15,514.54 | 0.06% | 1.25% | 7.69% | 8.98% | 0.0056% |
| Edison International | EIX | 22,503.84 | 0.09% | 4.10% | 4.81% | 9.01% | 0.0082% |
| Estee Lauder Cos Inc/The | EL | 62,653.48 | 0.25% | 1.03% | 11.33% | 12.42% | 0.0315% |
| Eastman Chemical Co | EMN | 7,487.77 | 0.03% | 4.79% | 5.27% | 10.18% | 0.0031% |
| Emerson Electric Co | EMR | 30,922.45 | 0.13% | 3.93% | 6.37% | 10.43% | 0.0130% |
| EOG Resources Inc | EOG | 24,353.18 | 0.10% | 3.40% | -4.97% | -1.66% | -0.0016% |
| Equinix Inc | EQIX | 59,379.23 | 0.24% | 1.53% | 21.46% | 23.15% | 0.0556% |
| Equity Residential | EQR | 25,960.38 | N/A | 3.43% | N/A | N/A | N/A |
| Eversource Energy | ES | 30,245.21 | 0.12% | 2.48% | 6.33% | 8.88% | 0.0109% |
| Essex Property Trust Inc | ESS | 17,262.75 | 0.07% | 3.15% | 6.30% | 9.55% | 0.0067% |
| E*TRADE Financial Corp | ETFC | 8,812.23 | 0.04% | 1.46% | 3.38% | 4.86% | 0.0017% |
| Eaton Corp PLC | ETN | 32,610.49 | 0.13% | 3.63% | 9.33% | 13.13% | 0.0173% |
| Entergy Corp | ETR | 20,336.60 | 0.08% | 3.70% | 2.85% | 6.59% | 0.0054% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Evergy Inc | EVRG | 13,821.67 | 0.06% | 3.35% | 5.63% | 9.08% | 0.0051% |
| Edwards Lifesciences Corp | EW | 47,355.31 | 0.19% | 0.00% | 13.18% | 13.18% | 0.0253% |
| Exelon Corp | EXC | 37,437.86 | 0.15% | 3.97% | 1.19% | 5.18% | 0.0079% |
| Expeditors International of Washington I | EXPD | 12,051.52 | 0.05% | 1.46% | 9.70% | 11.23% | 0.0055% |
| Expedia Group Inc | EXPE | 8,850.11 | 0.04% | 1.69% | 13.67% | 15.47% | 0.0055% |
| Extra Space Storage Inc | EXR | 12,055.88 | 0.05% | 3.92% | 4.17% | 8.17% | 0.0040% |
| Ford Motor Co | F | 20,360.64 | 0.08% | 6.74% | 11.67% | 18.80% | 0.0155% |
| Diamondback Energy Inc | FANG | 4,989.13 | 0.02% | 4.50% | 11.96% | 16.73% | 0.0034% |
| Fastenal Co | FAST | 20,581.38 | 0.08% | 2.74% | 13.85% | 16.78% | 0.0140% |
| Facebook Inc | FB | 510,974.40 | 2.07% | 0.00% | 20.64% | 20.64% | 0.4266% |
| Fortune Brands Home & Security Inc | FBHS | 6,510.31 | 0.03% | 2.06% | 5.63% | 7.75% | 0.0020% |
| Freeport-McMoRan Inc | FCX | 12,101.11 | 0.05% | 1.63% | 138.40% | 141.16% | 0.0691% |
| FedEx Corp | FDX | 32,617.03 | 0.13% | 2.09% | 14.06% | 16.29% | 0.0215% |
| FirstEnergy Corp | FE | 25,033.36 | 0.10% | 3.38% | 1.61% | 5.02% | 0.0051% |
| F5 Networks Inc | FFIV | 7,546.40 | 0.03% | 0.00% | 5.20% | 5.20% | 0.0016% |
| Fidelity National Information Services I | FIS | 79,045.62 | 0.32% | 1.15% | 18.45% | 19.71% | 0.0630% |
| Fiserv Inc | FISV | 68,059.71 | 0.28% | 0.00% | 14.77% | 14.77% | 0.0407% |
| Fifth Third Bancorp | FITB | 11,826.14 | 0.05% | 6.57% | 1.80% | 8.43% | 0.0040% |
| FLIR Systems Inc | FLIR | 4,591.66 | 0.02% | 2.14% | 10.40% | 12.65% | 0.0023% |
| Flowserve Corp | FLS | 3,226.79 | N/A | 3.19% | N/A | N/A | N/A |
| FleetCor Technologies Inc | FLT | 19,101.08 | 0.08% | 0.04% | 11.05% | 11.09% | 0.0086% |
| FMC Corp | FMC | 11,144.83 | 0.05% | 1.99% | 9.80% | 11.88% | 0.0054% |
| Fox Corp | FOXA | 16,139.63 | 0.07% | 1.69% | -9.57% | -7.97% | -0.0052% |
| First Republic Bank/CA | FRC | 17,132.19 | 0.07% | 0.79% | 6.49% | 7.31% | 0.0051% |
| Federal Realty Investment Trust | FRT | 5,698.92 | 0.02% | 5.61% | 6.08% | 11.86% | 0.0027% |
| TechnipFMC PLC | FTI | 3,630.17 | 0.01% | 6.40% | 3.00% | 9.50% | 0.0014% |
| Fortinet Inc | FTNT | 19,487.26 | 0.08% | 0.00% | 16.20% | 16.20% | 0.0128% |
| Fortive Corp | FTV | 20,306.03 | 0.08% | 0.51% | 5.90% | 6.42% | 0.0053% |
| General Dynamics Corp | GD | 40,104.52 | 0.16% | 3.13% | 7.18% | 10.42% | 0.0169% |
| General Electric Co | GE | 59,790.61 | 0.24% | 0.58% | 6.33% | 6.94% | 0.0168% |
| Gilead Sciences Inc | GILD | 105,744.68 | 0.43% | 3.23% | 0.80% | 4.04% | 0.0173% |
| General Mills Inc | GIS | 36,774.45 | 0.15% | 3.23% | 5.87% | 9.20% | 0.0137% |
| Globe Life Inc | GL | 8,296.43 | 0.03% | 0.93% | 5.95% | 6.91% | 0.0023% |
| Corning Inc | GLW | 15,801.49 | 0.06% | 4.35% | 9.40% | 13.96% | 0.0089% |
| General Motors Co | GM | 32,123.97 | 0.13% | 6.14% | 13.36% | 19.90% | 0.0259% |
| Alphabet Inc | GOOGL | 880,586.70 | 3.56% | 0.00% | 16.09% | 16.09% | 0.5734% |
| Genuine Parts Co | GPC | 10,852.74 | 0.04% | 4.20% | 2.58% | 6.83% | 0.0030% |
| Global Payments Inc | GPN | 46,483.90 | 0.19% | 0.38% | 20.52% | 20.95% | 0.0394% |
| Gap Inc/The | GPS | 3,111.54 | 0.01% | 10.92% | 8.50% | 19.89% | 0.0025% |
| Garmin Ltd | GRMN | 15,657.34 | 0.06% | 2.94% | 7.03% | 10.08% | 0.0064% |
| Goldman Sachs Group Inc/The | GS | 65,776.61 | 0.27% | 2.76% | 5.13% | 7.95% | 0.0212% |
| WW Grainger Inc | GWW | 15,040.27 | 0.06% | 2.14% | 11.50% | 13.76% | 0.0084% |
| Halliburton Co | HAL | 6,620.00 | N/A | 9.50% | N/A | N/A | N/A |
| Hasbro Inc | HAS | 10,302.92 | 0.04% | 3.69% | 10.61% | 14.50% | 0.0060% |
| Huntington Bancshares Inc/OH | HBAN | 8,245.19 | 0.03% | 7.51% | -9.95% | -2.81% | -0.0009% |
| Hanesbrands Inc | HBI | 3,296.11 | 0.01% | 6.55% | 2.89% | 9.53% | 0.0013% |
| HCA Healthcare Inc | HCA | 39,147.30 | 0.16% | 1.59% | 10.25% | 11.92% | 0.0189% |
| Home Depot Inc/The | HD | 224,941.40 | 0.91% | 2.80% | 9.49% | 12.43% | 0.1131% |
| Hess Corp | HES | 11,399.76 | N/A | 2.67% | N/A | N/A | N/A |
| HollyFrontier Corp | HFC | 4,374.09 | 0.02% | 5.20% | 1.40% | 6.64% | 0.0012% |
| Hartford Financial Services Group Inc/Th | HIG | 14,322.43 | 0.06% | 3.30% | 12.00% | 15.49% | 0.0090% |
| Huntington Ingalls Industries Inc | HII | 7,980.25 | 0.03% | 2.19% | 40.00% | 42.63% | 0.0138% |
| Hilton Worldwide Holdings Inc | HLT | 20,980.60 | 0.08% | 0.17% | 1.56% | 1.73% | 0.0015% |
| Harley-Davidson Inc | HOG | 2,963.17 | 0.01% | 6.81% | 7.70% | 14.77% | 0.0018% |
| Hologic Inc | HOLX | 11,566.11 | 0.05% | 0.00% | 11.10% | 11.10% | 0.0052% |
| Honeywell International Inc | HON | 97,831.89 | 0.40% | 2.60% | 6.19% | 8.87% | 0.0351% |
| Helmerich & Payne Inc | HP | 1,931.49 | N/A | 12.68% | N/A | N/A | N/A |
| Hewlett Packard Enterprise Co | HPE | 12,509.80 | 0.05% | 4.97% | 2.05% | 7.08% | 0.0036% |
| HP Inc | HPQ | 22,189.94 | 0.09% | 4.54% | 3.57% | 8.19% | 0.0074% |
| H&R Block Inc | HRB | 2,763.95 | 0.01% | 7.26% | 10.00% | 17.63% | 0.0020% |
| Hormel Foods Corp | HRL | 27,163.07 | 0.11% | 1.83% | 4.63% | 6.50% | 0.0071% |
| Henry Schein Inc | HSIC | 7,657.43 | 0.03% | 0.00% | 1.13% | 1.13% | 0.0003% |
| Host Hotels & Resorts Inc | HST | 8,025.88 | 0.03% | 6.11% | -2.30% | 3.74% | 0.0012% |
| Hershey Co/The | HSY | 30,655.63 | 0.12% | 2.18% | 7.70% | 9.96% | 0.0124% |
| Humana Inc | HUM | 49,360.15 | 0.20% | 0.65% | 11.97% | 12.66% | 0.0253% |
| Howmet Aerospace Inc | HWM | 5,078.45 | 0.02% | 0.00% | 51.10% | 51.10% | 0.0105% |
| International Business Machines Corp | IBM | 106,715.57 | 0.43% | 5.57% | 2.66% | 8.30% | 0.0359% |
| Intercontinental Exchange Inc | ICE | 49,642.04 | 0.20% | 1.31% | 9.77% | 11.14% | 0.0224% |
| IDEXX Laboratories Inc | IDXX | 22,598.24 | 0.09% | 0.00% | 17.29% | 17.29% | 0.0158% |
| IDEX Corp | IEX | 11,644.02 | 0.05% | 1.36% | 11.60% | 13.04% | 0.0061% |
| International Flavors & Fragrances Inc | IFF | 13,363.09 | 0.05% | 2.40% | 7.47% | 9.95% | 0.0054% |
| Illumina Inc | ILMN | 46,446.16 | 0.19% | 0.00% | 18.80% | 18.80% | 0.0353% |
| Incyte Corp | INCY | 21,677.55 | 0.09% | 0.00% | 20.20% | 20.20% | 0.0177% |
| IHS Markit Ltd | INFO | 26,795.22 | 0.11% | 0.71% | 12.20% | 12.95% | 0.0140% |
| Intel Corp | INTC | 258,372.40 | 1.05% | 2.18% | 6.94% | 9.19% | 0.0961% |
| Intuit Inc | INTU | 69,123.48 | 0.28% | 0.78% | 16.20% | 17.05% | 0.0477% |
| International Paper Co | IP | 12,530.77 | 0.05% | 6.44% | -30.30% | -24.84% | -0.0126% |
| Interpublic Group of Cos Inc/The | IPG | 5,864.96 | 0.02% | 6.35% | 0.13% | 6.48% | 0.0015% |
| IPG Photonics Corp | IPGP | 6,326.58 | N/A | 0.00% | N/A | N/A | N/A |
| IQVIA Holdings Inc | IQV | 25,368.87 | 0.10% | 0.00% | 11.85% | 11.85% | 0.0122% |
| Ingersoll Rand Inc | IR | 11,141.61 | 0.05% | 0.41% | 9.40% | 9.83% | 0.0044% |
| Iron Mountain Inc | IRM | 7,193.85 | 0.03% | 9.97% | 6.70% | 17.01% | 0.0049% |
| Intuitive Surgical Inc | ISRG | 61,041.18 | 0.25% | 0.00% | 7.87% | 7.87% | 0.0194% |
| Gartner Inc | IT | 9,441.21 | 0.04% | 0.00% | 10.82% | 10.82% | 0.0041% |
| Illinois Tool Works Inc | ITW | 50,351.92 | 0.20% | 2.60% | 5.65% | 8.32% | 0.0170% |
| Invesco Ltd | IVZ | 4,112.61 | 0.02% | 13.68% | -8.63% | 4.46% | 0.0007% |
| Jacobs Engineering Group Inc | J | 11,202.82 | 0.05% | 0.89% | 12.69% | 13.63% | 0.0062% |
| JB Hunt Transport Services Inc | JBHT | 11,431.34 | 0.05% | 1.00% | 11.70% | 12.76% | 0.0059% |
| Johnson Controls International plc | JCI | 22,569.96 | 0.09% | 3.66% | 9.67% | 13.50% | 0.0123% |
| Jack Henry & Associates Inc | JKHY | 13,016.25 | 0.05% | 0.97% | 12.10% | 13.13% | 0.0069% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Johnson & Johnson | JNJ | 400,778.27 | 1.62% | 2.62% | 5.85% | 8.55% | 0.1386% |
| Juniper Networks Inc | JNPR | 7,470.94 | 0.03% | 3.52% | 8.70% | 12.38% | 0.0037% |
| JPMorgan Chase & Co | JPM | 289,969.40 | 1.17% | 3.82% | 5.70% | 9.63% | 0.1130% |
| Nordstrom Inc | JWN | 2,939.31 | 0.01% | 3.98% | 6.00% | 10.10% | 0.0012% |
| Kellogg Co | K | 22,269.26 | 0.09% | 3.58% | 3.22% | 6.86% | 0.0062% |
| KeyCorp | KEY | 10,543.20 | 0.04% | 6.85% | 3.36% | 10.33% | 0.0044% |
| Keysight Technologies Inc | KEYS | 17,959.97 | 0.07% | 0.00% | 20.00% | 20.00% | 0.0145% |
| Kraft Heinz Co/The | KHC | 35,834.13 | 0.14% | 5.35% | -0.21% | 5.14% | 0.0075% |
| Kimco Realty Corp | KIM | 3,857.98 | 0.02% | 12.15% | 4.72% | 17.16% | 0.0027% |
| KLA Corp | KLAC | 25,273.25 | 0.10% | 2.10% | 11.04% | 13.26% | 0.0136% |
| Kimberly-Clark Corp | KMB | 48,466.87 | 0.20% | 3.00% | 4.51% | 7.57% | 0.0149% |
| Kinder Morgan Inc | KMI | 33,861.06 | 0.14% | 8.02% | 5.60% | 13.85% | 0.0190% |
| CarMax Inc | KMX | 10,636.17 | 0.04% | 0.00% | 11.64% | 11.64% | 0.0050% |
| Coca-Cola Co/The | KO | 206,340.88 | 0.83% | 3.44% | 4.66% | 8.18% | 0.0683% |
| Kroger Co/The | KR | 24,838.09 | 0.10% | 2.06% | 5.25% | 7.37% | 0.0074% |
| Kohl's Corp | KSS | 2,868.96 | 0.01% | 13.46% | 8.00% | 22.00% | 0.0026% |
| Kansas City Southern | KSU | 13,242.02 | 0.05% | 1.12% | 11.00% | 12.18% | 0.0065% |
| Loews Corp | L | 10,232.55 | N/A | 0.00% | N/A | N/A | N/A |
| L Brands Inc | LB | 3,810.63 | 0.02% | 6.71% | 11.50% | 18.60% | 0.0029% |
| Leidos Holdings Inc | LDOS | 14,082.58 | 0.06% | 1.40% | 9.93% | 11.39% | 0.0065% |
| Leggett & Platt Inc | LEG | 3,820.68 | N/A | 5.68% | N/A | N/A | N/A |
| Lennar Corp | LEN | 13,021.50 | 0.05% | 0.77% | 9.66% | 10.46% | 0.0055% |
| Laboratory Corp of America Holdings | LH | 14,421.79 | 0.06% | 0.00% | 5.12% | 5.12% | 0.0030% |
| L3Harris Technologies Inc | LHX | 44,138.38 | 0.18% | 1.64% | 16.72% | 18.50% | 0.0330% |
| Linde PLC | LIN | 100,250.82 | 0.41% | 2.02% | 9.50% | 11.62% | 0.0471% |
| LKQ Corp | LKQ | 6,441.51 | 0.03% | 0.00% | 14.20% | 14.20% | 0.0037% |
| Eli Lilly & Co | LLY | 150,532.58 | 0.61% | 1.89% | 10.88% | 12.87% | 0.0784% |
| Lockheed Martin Corp | LMT | 113,172.98 | 0.46% | 2.46% | 7.76% | 10.31% | 0.0472% |
| Lincoln National Corp | LNC | 5,794.72 | 0.02% | 5.55% | 9.00% | 14.80% | 0.0035% |
| Alliant Energy Corp | LNT | 12,965.24 | 0.05% | 2.86% | 5.83% | 8.78% | 0.0046% |
| Lowe's Cos Inc | LOW | 73,305.51 | 0.30% | 2.48% | 16.29% | 18.98% | 0.0563% |
| Lam Research Corp | LRCX | 40,610.93 | 0.16% | 1.68% | 12.09% | 13.87% | 0.0228% |
| Southwest Airlines Co | LUV | 15,868.50 | 0.06% | 1.62% | 4.03% | 5.68% | 0.0036% |
| Las Vegas Sands Corp | LVS | 35,902.93 | 0.15% | 5.76% | 6.10% | 12.04% | 0.0175% |
| Lamb Weston Holdings Inc | LW | 8,750.65 | 0.04% | 1.43% | -1.85% | -0.43% | -0.0002% |
| LyondellBasell Industries NV | LYB | 17,411.52 | 0.07% | 8.25% | 6.20% | 14.71% | 0.0104% |
| Live Nation Entertainment Inc | LYV | 8,227.27 | N/A | 0.00% | N/A | N/A | N/A |
| Mastercard Inc | MA | 261,298.18 | 1.06% | 0.55% | 16.43% | 17.03% | 0.1800% |
| Mid-America Apartment Communities Inc | MAA | 12,970.74 | N/A | 3.53% | N/A | N/A | N/A |
| Marriott International Inc/MD | MAR | 27,318.88 | 0.11% | 0.57% | 0.42% | 0.99% | 0.0011% |
| Masco Corp | MAS | 10,547.58 | 0.04% | 1.36% | 10.18% | 11.61% | 0.0050% |
| McDonald's Corp | MCD | 138,368.16 | 0.56% | 2.68% | 7.15% | 9.93% | 0.0556% |
| Microchip Technology Inc | MCHP | 19,244.49 | 0.08% | 1.69% | 8.31% | 10.07% | 0.0078% |
| McKesson Corp | MCK | 22,870.57 | 0.09% | 1.17% | 3.90% | 5.08% | 0.0047% |
| Moody's Corp | MCO | 44,810.04 | 0.18% | 0.94% | 11.70% | 12.69% | 0.0230% |
| Mondelez International Inc | MDLZ | 76,460.05 | 0.31% | 2.18% | 7.80% | 10.07% | 0.0311% |
| Medtronic PLC | MDT | 138,479.37 | 0.56% | 2.07% | 7.38% | 9.52% | 0.0534% |
| MetLife Inc | MET | 30,277.28 | 0.12% | 5.59% | 4.58% | 10.30% | 0.0126% |
| MGM Resorts International | MGM | 6,937.09 | 0.03% | 3.81% | 16.23% | 20.35% | 0.0057% |
| Mohawk Industries Inc | MHK | 5,666.28 | 0.02% | 0.00% | 1.57% | 1.57% | 0.0004% |
| McCormick & Co Inc/MD | MKC | 20,835.66 | 0.08% | 1.54% | 9.17% | 10.78% | 0.0091% |
| MarketAxess Holdings Inc | MKTX | 16,297.93 | N/A | 0.55% | N/A | N/A | N/A |
| Martin Marietta Materials Inc | MLM | 12,358.52 | 0.05% | 1.06% | 13.48% | 14.61% | 0.0073% |
| Marsh & McLennan Cos Inc | MMC | 49,673.63 | 0.20% | 1.93% | 11.12% | 13.16% | 0.0264% |
| 3M Co | MMM | 84,252.68 | 0.34% | 4.03% | 7.05% | 11.22% | 0.0382% |
| Monster Beverage Corp | MNST | 33,389.57 | 0.14% | 0.00% | 7.90% | 7.90% | 0.0107% |
| Altria Group Inc | MO | 75,914.34 | 0.31% | 8.32% | 5.25% | 13.79% | 0.0424% |
| Mosaic Co/The | MOS | 4,339.78 | 0.02% | 1.76% | 7.00% | 8.83% | 0.0015% |
| Marathon Petroleum Corp | MPC | 16,542.52 | 0.07% | 9.17% | 15.18% | 25.04% | 0.0168% |
| Merck & Co Inc | MRK | 210,743.74 | 0.85% | 2.88% | 7.72% | 10.71% | 0.0913% |
| Marathon Oil Corp | MRO | 3,438.32 | 0.01% | 4.60% | -3.20% | 1.32% | 0.0002% |
| Morgan Stanley | MS | 61,605.84 | 0.25% | 3.66% | -0.03% | 3.63% | 0.0091% |
| MSCI Inc | MSCI | 26,964.98 | 0.11% | 0.89% | 13.17% | 14.11% | 0.0154% |
| Microsoft Corp | MSFT | 1,358,440.00 | 5.50% | 1.11% | 12.86% | 14.04% | 0.7716% |
| Motorola Solutions Inc | MSI | 27,065.95 | 0.11% | 1.61% | 8.90% | 10.58% | 0.0116% |
| M&T Bank Corp | MTB | 13,707.19 | 0.06% | 4.21% | -0.73% | 3.46% | 0.0019% |
| Mettler-Toledo International Inc | MTD | 17,287.80 | 0.07% | 0.00% | 12.16% | 12.16% | 0.0085% |
| Micron Technology Inc | MU | 50,826.90 | 0.21% | 0.00% | 6.95% | 6.95% | 0.0143% |
| Maxim Integrated Products Inc | MXIM | 14,302.14 | 0.06% | 3.62% | 10.00% | 13.80% | 0.0080% |
| Mylan NV | MYL | 8,315.61 | 0.03% | 0.70% | 0.43% | 1.14% | 0.0004% |
| Noble Energy Inc | NBL | 3,371.03 | 0.01% | 4.99% | 5.87% | 11.00% | 0.0015% |
| Norwegian Cruise Line Holdings Ltd | NCLH | 2,639.45 | 0.01% | 0.21% | -56.12% | -55.97% | -0.0060% |
| Nasdaq Inc | NDAQ | 18,282.05 | 0.07% | 1.78% | 12.01% | 13.90% | 0.0103% |
| NextEra Energy Inc | NEE | 120,527.74 | 0.49% | 2.28% | 8.32% | 10.70% | 0.0522% |
| Newmont Corp | NEM | 47,845.25 | 0.19% | 1.64% | -3.00% | -1.39% | -0.0027% |
| Netflix Inc | NFLX | 185,597.66 | 0.75% | 0.00% | 26.38% | 26.38% | 0.1981% |
| NiSource Inc | NI | 10,095.19 | 0.04% | 3.21% | 4.68% | 7.97% | 0.0033% |
| NIKE Inc | NKE | 139,813.17 | 0.57% | 1.04% | 12.09% | 13.19% | 0.0746% |
| NortonLifeLock Inc | NLOK | 12,079.73 | 0.05% | 41.53% | 2.05% | 44.01% | 0.0215% |
| Nielsen Holdings PLC | NLSN | 4,726.86 | 0.02% | 1.81% | 8.75% | 10.64% | 0.0020% |
| Northrop Grumman Corp | NOC | 59,606.57 | 0.24% | 1.57% | 20.99% | 22.73% | 0.0548% |
| National Oilwell Varco Inc | NOV | 4,530.56 | N/A | 1.69% | N/A | N/A | N/A |
| ServiceNow Inc | NOW | 56,862.18 | 0.23% | 0.00% | 30.15% | 30.15% | 0.0694% |
| NRG Energy Inc | NRG | 7,859.50 | 0.03% | 3.83% | -11.51% | -7.90% | -0.0025% |
| Norfolk Southern Corp | NSC | 41,308.99 | 0.17% | 2.36% | 6.95% | 9.40% | 0.0157% |
| NetApp Inc | NTAP | 9,322.61 | 0.04% | 4.54% | 5.20% | 9.86% | 0.0037% |
| Northern Trust Corp | NTRS | 16,741.35 | 0.07% | 3.57% | -2.87% | 0.65% | 0.0004% |
| Nucor Corp | NUE | 11,236.45 | 0.05% | 4.31% | 12.00% | 16.57% | 0.0075% |
| NVIDIA Corp | NVDA | 179,041.78 | 0.72% | 0.23% | 14.44% | 14.68% | 0.1063% |
| NVR Inc | NVR | 10,760.76 | 0.04% | 0.00% | 8.89% | 8.89% | 0.0039% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Newell Brands Inc | NWL | 5,760.95 | 0.02% | 6.69% | -2.82% | 3.77% | 0.0009% |
| News Corp | NWSA | 5,289.47 | 0.02% | 2.11% | -9.39% | -7.38% | -0.0016% |
| Realty Income Corp | O | 17,983.75 | 0.07% | 5.34% | 3.73% | 9.17% | 0.0067% |
| Old Dominion Freight Line Inc | ODFL | 16,335.95 | 0.07% | 0.51% | 8.99% | 9.52% | 0.0063% |
| ONEOK Inc | OKE | 12,159.12 | 0.05% | 12.81% | 9.15% | 22.55% | 0.0111% |
| Omnicom Group Inc | OMC | 11,834.47 | 0.05% | 4.86% | 4.13% | 9.09% | 0.0044% |
| Oracle Corp | ORCL | 172,248.76 | 0.70% | 1.75% | 9.25% | 11.08% | 0.0772% |
| O'Reilly Automotive Inc | ORLY | 27,733.70 | 0.11% | 0.00% | 9.19% | 9.19% | 0.0103% |
| Otis Worldwide Corp | OTIS | 19,986.62 | N/A | 0.00% | N/A | N/A | N/A |
| Occidental Petroleum Corp | OXY | 12,267.25 | 0.05% | 11.94% | -1.50% | 10.35% | 0.0051% |
| Paycom Software Inc | PAYC | 13,236.54 | 0.05% | 0.00% | 22.35% | 22.35% | 0.0120% |
| Paychex Inc | PAYX | 24,213.29 | 0.10% | 3.69% | 7.00% | 10.82% | 0.0106% |
| People's United Financial Inc | PBCT | 4,875.11 | 0.02% | 6.23% | 2.00% | 8.29% | 0.0016% |
| PACCAR Inc | PCAR | 23,433.43 | 0.09% | 4.14% | 0.70% | 4.85% | 0.0046% |
| Healthpeak Properties Inc | PEAK | 13,277.88 | 0.05% | 5.65% | 3.04% | 8.77% | 0.0047% |
| Public Service Enterprise Group Inc | PEG | 27,590.05 | 0.11% | 3.59% | 4.52% | 8.19% | 0.0091% |
| PepsiCo Inc | PEP | 191,090.10 | 0.77% | 2.92% | 4.16% | 7.14% | 0.0552% |
| Pfizer Inc | PFE | 204,763.36 | 0.83% | 4.08% | 3.10% | 7.25% | 0.0600% |
| Principal Financial Group Inc | PFG | 8,347.92 | 0.03% | 7.44% | 1.95% | 9.46% | 0.0032% |
| Procter & Gamble Co/The | PG | 307,916.08 | 1.25% | 2.39% | 7.20% | 9.68% | 0.1206% |
| Progressive Corp/The | PGR | 48,287.25 | 0.20% | 3.27% | 6.00% | 9.37% | 0.0183% |
| Parker-Hannifin Corp | PH | 17,791.13 | 0.07% | 2.56% | 9.19% | 11.86% | 0.0085% |
| PulteGroup Inc | PHM | 6,877.13 | 0.03% | 1.87% | 10.77% | 12.74% | 0.0035% |
| Packaging Corp of America | PKG | 8,616.17 | 0.03% | 3.48% | -4.10% | -0.69% | -0.0002% |
| PerkinElmer Inc | PKI | 9,308.39 | 0.04% | 0.33% | 5.14% | 5.49% | 0.0021% |
| Prologis Inc | PLD | 66,680.66 | 0.27% | 2.52% | 6.72% | 9.32% | 0.0252% |
| Philip Morris International Inc | PM | 121,391.95 | 0.49% | 6.11% | 6.45% | 12.75% | 0.0626% |
| PNC Financial Services Group Inc/The | PNC | 43,036.00 | 0.17% | 4.55% | -3.03% | 1.46% | 0.0025% |
| Pentair PLC | PNR | 5,307.32 | 0.02% | 2.37% | 4.33% | 6.75% | 0.0015% |
| Pinnacle West Capital Corp | PNW | 8,988.98 | 0.04% | 3.96% | 4.59% | 8.64% | 0.0031% |
| PPG Industries Inc | PPG | 22,012.81 | 0.09% | 2.25% | 4.54% | 6.83% | 0.0061% |
| PPL Corp | PPL | 20,272.26 | 0.08% | 6.29% | 0.70% | 7.01% | 0.0057% |
| Perrigo Co PLC | PRGO | 7,060.89 | 0.03% | 1.75% | -1.00% | 0.75% | 0.0002% |
| Prudential Financial Inc | PRU | 22,416.09 | 0.09% | 7.77% | 7.83% | 15.91% | 0.0144% |
| Public Storage | PSA | 34,312.67 | 0.14% | 4.14% | 4.09% | 8.32% | 0.0115% |
| Phillips 66 | PSX | 26,064.48 | 0.11% | 6.21% | 7.02% | 13.45% | 0.0142% |
| PVH Corp | PVH | 3,181.25 | 0.01% | 0.16% | 2.97% | 3.13% | 0.0004% |
| Quanta Services Inc | PWR | 4,822.19 | 0.02% | 0.55% | 10.00% | 10.58% | 0.0021% |
| Pioneer Natural Resources Co | PXD | 12,633.46 | 0.05% | 2.83% | 18.98% | 22.08% | 0.0113% |
| PayPal Holdings Inc | PYPL | 131,187.87 | 0.53% | 0.00% | 22.44% | 22.44% | 0.1191% |
| QUALCOMM Inc | QCOM | 87,065.57 | 0.35% | 3.33% | 16.31% | 19.91% | 0.0701% |
| Qorvo Inc | QRVO | 9,980.11 | 0.04% | 0.05% | 11.15% | 11.20% | 0.0045% |
| Royal Caribbean Cruises Ltd | RCL | 7,814.51 | 0.03% | 6.65% | -29.88% | -24.22% | -0.0077% |
| Everest Re Group Ltd | RE | 8,941.96 | 0.04% | 2.72% | 10.00% | 12.86% | 0.0047% |
| Regency Centers Corp | REG | 6,490.31 | 0.03% | 5.69% | 5.68% | 11.53% | 0.0030% |
| Regeneron Pharmaceuticals Inc | REGN | 62,578.17 | 0.25% | 0.00% | 8.74% | 8.74% | 0.0221% |
| Regions Financial Corp | RF | 9,114.38 | 0.04% | 6.68% | -3.62% | 2.94% | 0.0011% |
| Robert Half International Inc | RHI | 4,961.41 | 0.02% | 3.04% | -1.18% | 1.85% | 0.0004% |
| Raymond James Financial Inc | RJF | 8,868.21 | 0.04% | 2.26% | 9.50% | 11.87% | 0.0043% |
| Ralph Lauren Corp | RL | 5,359.65 | 0.02% | 3.75% | 2.62% | 6.41% | 0.0014% |
| ResMed Inc | RMD | 23,884.93 | 0.10% | 1.04% | 15.88% | 17.00% | 0.0164% |
| Rockwell Automation Inc | ROK | 19,587.40 | 0.08% | 2.41% | 5.75% | 8.23% | 0.0065% |
| Rollins Inc | ROL | 12,770.19 | N/A | 1.36% | N/A | N/A | N/A |
| Roper Technologies Inc | ROP | 34,164.13 | 0.14% | 0.63% | 11.93% | 12.60% | 0.0174% |
| Ross Stores Inc | ROST | 32,596.10 | 0.13% | 1.18% | 8.67% | 9.90% | 0.0131% |
| Republic Services Inc | RSG | 25,621.64 | 0.10% | 2.06% | 5.05% | 7.16% | 0.0074% |
| Raytheon Technologies Corp | RTX | 100,179.89 | 0.41% | 3.25% | -3.56% | -0.36% | -0.0015% |
| SBA Communications Corp | SBAC | 35,324.27 | 0.14% | 0.60% | 10.00% | 10.63% | 0.0152% |
| Starbucks Corp | SBUX | 90,492.27 | 0.37% | 2.16% | 13.60% | 15.91% | 0.0582% |
| Charles Schwab Corp/The | SCHW | 46,071.60 | 0.19% | 2.02% | 5.00% | 7.07% | 0.0132% |
| Sealed Air Corp | SEE | 4,591.90 | 0.02% | 2.15% | 4.67% | 6.87% | 0.0013% |
| Sherwin-Williams Co/The | SHW | 47,439.70 | 0.19% | 0.99% | 11.71% | 12.75% | 0.0245% |
| SVB Financial Group | SIVB | 8,953.17 | 0.04% | 0.00% | 8.00% | 8.00% | 0.0029% |
| JM Smucker Co/The | SJM | 13,864.73 | 0.06% | 2.83% | 0.49% | 3.33% | 0.0019% |
| Schlumberger Ltd | SLB | 21,211.12 | 0.09% | 10.29% | 50.00% | 62.87% | 0.0540% |
| SL Green Realty Corp | SLG | 4,047.53 | 0.02% | 6.69% | 4.98% | 11.84% | 0.0019% |
| Snap-on Inc | SNA | 6,471.17 | 0.03% | 3.58% | 5.06% | 8.73% | 0.0023% |
| Synopsys Inc | SNPS | 23,282.20 | 0.09% | 0.00% | 14.14% | 14.14% | 0.0133% |
| Southern Co/The | SO | 60,746.17 | 0.25% | 4.42% | 4.18% | 8.70% | 0.0214% |
| Simon Property Group Inc | SPG | 17,151.52 | 0.07% | 14.47% | 1.83% | 16.44% | 0.0114% |
| S&P Global Inc | SPGI | 68,087.05 | 0.28% | 0.90% | 11.80% | 12.76% | 0.0351% |
| Sempra Energy | SRE | 36,385.33 | 0.15% | 3.36% | 7.22% | 10.71% | 0.0158% |
| STERIS PLC | STE | 13,143.49 | 0.05% | 0.93% | 10.10% | 11.08% | 0.0059% |
| State Street Corp | STT | 20,600.21 | 0.08% | 3.60% | 1.83% | 5.46% | 0.0045% |
| Seagate Technology PLC | STX | 13,431.41 | 0.05% | 4.99% | 8.11% | 13.30% | 0.0072% |
| Constellation Brands Inc | STZ | 31,291.39 | 0.13% | 1.87% | 2.11% | 4.00% | 0.0051% |
| Stanley Black & Decker Inc | SWK | 17,334.03 | 0.07% | 2.48% | 4.87% | 7.41% | 0.0052% |
| Skyworks Solutions Inc | SWKS | 16,176.29 | 0.07% | 1.85% | 11.84% | 13.80% | 0.0090% |
| Synchrony Financial | SYF | 9,110.09 | 0.04% | 5.73% | -7.98% | -2.48% | -0.0009% |
| Stryker Corp | SYK | 71,033.69 | 0.29% | 1.22% | 8.90% | 10.17% | 0.0292% |
| Sysco Corp | SYY | 25,583.07 | 0.10% | 3.46% | 8.97% | 12.58% | 0.0130% |
| AT&T Inc | T | 224,328.39 | 0.91% | 6.68% | 4.62% | 11.45% | 0.1040% |
| Molson Coors Beverage Co | TAP | 9,739.03 | 0.04% | 4.95% | -6.37% | -1.58% | -0.0006% |
| TransDigm Group Inc | TDG | 18,114.22 | 0.07% | 3.85% | 7.17% | 11.16% | 0.0082% |
| TE Connectivity Ltd | TEL | 22,534.54 | 0.09% | 2.73% | 7.18% | 10.01% | 0.0091% |
| Truist Financial Corp | TFC | 44,923.05 | 0.18% | 5.49% | -2.44% | 2.98% | 0.0054% |
| Teleflex Inc | TFX | 16,075.80 | 0.07% | 0.39% | 13.53% | 13.95% | 0.0091% |
| Target Corp | TGT | 56,819.10 | 0.23% | 2.46% | 9.41% | 11.98% | 0.0275% |
| Tiffany & Co | TIF | 15,651.86 | N/A | 1.90% | N/A | N/A | N/A |
| TJX Cos Inc/The | TJX | 59,561.53 | 0.24% | 1.49% | 8.40% | 9.95% | 0.0240% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Thermo Fisher Scientific Inc | TMO | 130,957.89 | 0.53% | 0.25% | 10.60% | 10.87% | 0.0576% |
| T-Mobile US Inc | TMUS | 111,852.65 | 0.45% | 0.66% | 6.00% | 6.68% | 0.0302% |
| Tapestry Inc | TPR | 4,201.16 | 0.02% | 7.98% | 9.30% | 17.65% | 0.0030% |
| T Rowe Price Group Inc | TROW | 24,150.92 | 0.10% | 3.46% | -2.96% | 0.46% | 0.0004% |
| Travelers Cos Inc/The | TRV | 26,569.81 | 0.11% | 3.25% | 10.00% | 13.41% | 0.0144% |
| Tractor Supply Co | TSCO | 10,757.81 | 0.04% | 1.57% | 10.45% | 12.10% | 0.0053% |
| Tyson Foods Inc | TSN | 22,756.48 | 0.09% | 2.73% | 5.44% | 8.24% | 0.0076% |
| Trane Technologies PLC | TT | 21,434.64 | 0.09% | 2.33% | 2.51% | 4.86% | 0.0042% |
| Take-Two Interactive Software Inc | TTWO | 14,114.52 | 0.06% | 0.00% | 8.70% | 8.70% | 0.0050% |
| Twitter Inc | TWTR | 20,949.60 | 0.08% | 0.00% | 39.40% | 39.40% | 0.0334% |
| Texas Instruments Inc | TXN | 106,019.99 | 0.43% | 3.20% | 7.50% | 10.82% | 0.0464% |
| Textron Inc | TXT | 6,317.16 | N/A | 0.29% | N/A | N/A | N/A |
| Under Armour Inc | UAA | 4,214.98 | 0.02% | 0.00% | 12.77% | 12.77% | 0.0022% |
| United Airlines Holdings Inc | UAL | 7,190.23 | 0.03% | 0.00% | 1.56% | 1.56% | 0.0005% |
| UDR Inc | UDR | 11,482.67 | N/A | 3.69% | N/A | N/A | N/A |
| Universal Health Services Inc | UHS | 9,227.72 | 0.04% | 0.74% | 8.59% | 9.36% | 0.0035% |
| Ulta Beauty Inc | ULTA | 12,135.26 | 0.05% | 0.00% | 15.68% | 15.68% | 0.0077% |
| UnitedHealth Group Inc | UNH | 275,617.48 | 1.12% | 1.58% | 11.80% | 13.47% | 0.1502% |
| Unum Group | UNM | 3,153.57 | 0.01% | 7.59% | 9.00% | 16.93% | 0.0022% |
| Union Pacific Corp | UNP | 101,708.45 | 0.41% | 2.60% | 7.50% | 10.20% | 0.0420% |
| United Parcel Service Inc | UPS | 88,205.40 | 0.36% | 3.90% | 8.45% | 12.51% | 0.0447% |
| United Rentals Inc | URI | 7,781.89 | 0.03% | 0.00% | -15.30% | -15.30% | -0.0048% |
| US Bancorp | USB | 52,800.36 | 0.21% | 4.80% | 6.43% | 11.38% | 0.0243% |
| Visa Inc | V | 332,723.43 | 1.35% | 0.69% | 14.60% | 15.34% | 0.2066% |
| Varian Medical Systems Inc | VAR | 10,494.57 | 0.04% | 0.00% | 8.40% | 8.40% | 0.0036% |
| VF Corp | VFC | 22,696.42 | 0.09% | 3.29% | 6.88% | 10.28% | 0.0094% |
| ViacomCBS Inc | VIAC | 9,838.01 | 0.04% | 5.81% | 1.85% | 7.71% | 0.0031% |
| Valero Energy Corp | VLO | 21,146.33 | 0.09% | 7.63% | 8.06% | 16.00% | 0.0137% |
| Vulcan Materials Co | VMC | 14,850.17 | 0.06% | 1.07% | 15.30% | 16.46% | 0.0099% |
| Vornado Realty Trust | VNO | 8,035.92 | 0.03% | 8.02% | 3.80% | 11.97% | 0.0039% |
| Verisk Analytics Inc | VRSK | 24,983.47 | 0.10% | 0.70% | 10.00% | 10.74% | 0.0109% |
| VeriSign Inc | VRSN | 24,301.69 | 0.10% | 0.00% | 4.00% | 4.00% | 0.0039% |
| Vertex Pharmaceuticals Inc | VRTX | 70,121.78 | 0.28% | 0.00% | 41.58% | 41.58% | 0.1180% |
| Ventas Inc | VTR | 11,673.17 | 0.05% | 9.63% | -2.32% | 7.20% | 0.0034% |
| Verizon Communications Inc | VZ | 241,782.60 | 0.98% | 4.25% | 2.96% | 7.27% | 0.0711% |
| Westinghouse Air Brake Technologies Corp | WAB | 9,358.60 | 0.04% | 1.01% | 15.00% | 16.09% | 0.0061% |
| Waters Corp | WAT | 12,244.36 | 0.05% | 0.00% | 3.98% | 3.98% | 0.0020% |
| Walgreens Boots Alliance Inc | WBA | 39,036.30 | 0.16% | 4.17% | 9.09% | 13.45% | 0.0212% |
| Western Digital Corp | WDC | 12,650.78 | 0.05% | 4.73% | 3.52% | 8.33% | 0.0043% |
| WEC Energy Group Inc | WEC | 31,650.70 | 0.13% | 2.50% | 6.60% | 9.18% | 0.0118% |
| Welltower Inc | WELL | 20,158.28 | 0.08% | 6.94% | 0.50% | 7.45% | 0.0061% |
| Wells Fargo & Co | WFC | 116,255.83 | 0.47% | 7.21% | 9.41% | 16.95% | 0.0797% |
| Whirlpool Corp | WHR | 6,601.85 | 0.03% | 4.77% | 0.17% | 4.94% | 0.0013% |
| Willis Towers Watson PLC | WLTW | 25,150.75 | 0.10% | 1.44% | 10.00% | 11.51% | 0.0117% |
| Waste Management Inc | WM | 42,477.10 | N/A | 2.18% | N/A | N/A | N/A |
| Williams Cos Inc/The | WMB | 21,933.27 | 0.09% | 8.81% | 3.50% | 12.47% | 0.0111% |
| Walmart Inc | WMT | 374,200.47 | 1.51% | 1.65% | 5.30% | 6.99% | 0.1058% |
| WR Berkley Corp | WRB | 10,453.20 | N/A | 2.40% | N/A | N/A | N/A |
| Westrock Co | WRK | 7,932.02 | 0.03% | 6.04% | -10.90% | -5.19% | -0.0017% |
| Western Union Co/The | WU | 8,188.67 | 0.03% | 4.40% | 5.33% | 9.85% | 0.0033% |
| Weyerhaeuser Co | WY | 14,998.74 | N/A | 6.77% | N/A | N/A | N/A |
| Wynn Resorts Ltd | WYNN | 8,435.72 | 0.03% | 3.43% | 21.50% | 25.30% | 0.0086% |
| Xcel Energy Inc | XEL | 35,255.73 | 0.14% | 2.56% | 5.92% | 8.56% | 0.0122% |
| Xilinx Inc | XLNX | 22,146.45 | 0.09% | 1.66% | 6.87% | 8.58% | 0.0077% |
| Exxon Mobil Corp | XOM | 182,839.20 | 0.74% | 7.83% | 1.73% | 9.62% | 0.0711% |
| DENTSPLY SIRONA Inc | XRAY | 8,949.41 | 0.04% | 0.93% | 3.27% | 4.22% | 0.0015% |
| Xerox Holdings Corp | XRX | 3,856.51 | N/A | 5.53% | N/A | N/A | N/A |
| Xylem Inc/NY | XYL | 12,520.35 | 0.05% | 1.47% | 11.65% | 13.21% | 0.0067% |
| Yum! Brands Inc | YUM | 25,326.75 | 0.10% | 2.14% | 12.00% | 14.27% | 0.0146% |
| Zimmer Biomet Holdings Inc | ZBH | 24,508.30 | 0.10% | 0.86% | 4.89% | 5.78% | 0.0057% |
| Zebra Technologies Corp | ZBRA | 10,771.13 | 0.04% | 0.00% | 11.05% | 11.05% | 0.0048% |
| Zions Bancorp NA | ZION | 4,769.50 | 0.02% | 4.80% | -5.41% | -0.74% | -0.0001% |
| Zoetis Inc | ZTS | 62,080.30 | N/A | 0.61% | N/A | N/A | N/A |
| | Total Market Capitalization: | 24,715,828 | | | | | 12.93% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

| [1] S&P 500 Est. Required Market Return | [2] Current 30-Year Treasury (30-day average) | [3] Implied Market Risk Premium |
|---|---|---|
| 14.82% | 1.37% | 13.45% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Agilent Technologies Inc | A | 23,773.90 | 0.11% | 0.94% | 10.50% | 11.49% | 0.0123% |
| American Airlines Group Inc | AAL | 4,851.54 | 0.02% | 3.53% | 6.50% | 10.14% | 0.0022% |
| Advance Auto Parts Inc | AAP | 7,097.67 | 0.03% | 0.98% | 14.00% | 15.05% | 0.0048% |
| Apple Inc | AAPL | 1,166,706.00 | 5.23% | 1.23% | 14.00% | 15.32% | 0.8014% |
| AbbVie Inc | ABBV | 116,183.20 | 0.52% | 6.01% | 8.00% | 14.25% | 0.0743% |
| AmerisourceBergen Corp | ABC | 18,176.37 | 0.08% | 1.90% | 7.50% | 9.47% | 0.0077% |
| ABIOMED Inc | ABMD | 7,049.81 | 0.03% | 0.00% | 11.00% | 11.00% | 0.0035% |
| Abbott Laboratories | ABT | 150,230.30 | 0.67% | 1.70% | 10.50% | 12.29% | 0.0828% |
| Accenture PLC | ACN | 109,532.70 | 0.49% | 1.91% | 8.50% | 10.49% | 0.0515% |
| Adobe Inc | ADBE | 153,197.90 | 0.69% | 0.00% | 20.50% | 20.50% | 0.1408% |
| Analog Devices Inc | ADI | 37,337.51 | 0.17% | 2.45% | 7.00% | 9.54% | 0.0160% |
| Archer-Daniels-Midland Co | ADM | 20,319.36 | 0.09% | 3.95% | 9.00% | 13.13% | 0.0120% |
| Automatic Data Processing Inc | ADP | 59,817.25 | 0.27% | 2.79% | 13.50% | 16.48% | 0.0442% |
| Alliance Data Systems Corp | ADS | 1,937.80 | 0.01% | 6.19% | 8.00% | 14.44% | 0.0013% |
| Autodesk Inc | ADSK | 35,031.45 | N/A | 0.00% | N/A | N/A | N/A |
| Ameren Corp | AEE | 18,713.66 | 0.08% | 2.67% | 6.00% | 8.75% | 0.0073% |
| American Electric Power Co Inc | AEP | 41,164.28 | 0.18% | 3.46% | 5.00% | 8.55% | 0.0158% |
| AES Corp/VA | AES | 9,380.81 | N/A | 4.03% | N/A | N/A | N/A |
| Aflac Inc | AFL | 27,450.97 | 0.12% | 2.99% | 7.00% | 10.09% | 0.0124% |
| Allergan PLC | AGN | 59,412.34 | 0.27% | 1.64% | 2.50% | 4.16% | 0.0111% |
| American International Group Inc | AIG | 20,993.08 | N/A | 5.31% | N/A | N/A | N/A |
| Apartment Investment & Management Co | AIV | 5,575.97 | 0.03% | 4.49% | -1.50% | 2.96% | 0.0007% |
| Assurant Inc | AIZ | 6,484.20 | 0.03% | 2.36% | 8.00% | 10.45% | 0.0030% |
| Arthur J Gallagher & Co | AJG | 15,859.96 | 0.07% | 2.12% | 14.50% | 16.77% | 0.0119% |
| Akamai Technologies Inc | AKAM | 15,774.04 | 0.07% | 0.00% | 14.00% | 14.00% | 0.0099% |
| Albemarle Corp | ALB | 6,555.39 | 0.03% | 2.49% | 5.50% | 8.06% | 0.0024% |
| Align Technology Inc | ALGN | 14,533.17 | 0.07% | 0.00% | 20.00% | 20.00% | 0.0130% |
| Alaska Air Group Inc | ALK | 3,584.22 | 0.02% | 5.15% | 6.50% | 11.82% | 0.0019% |
| Allstate Corp/The | ALL | 31,022.75 | 0.14% | 2.22% | 9.00% | 11.32% | 0.0157% |
| Allegion plc | ALLE | 8,776.33 | 0.04% | 1.35% | 9.00% | 10.41% | 0.0041% |
| Alexion Pharmaceuticals Inc | ALXN | 21,811.33 | 0.10% | 0.00% | 37.50% | 37.50% | 0.0367% |
| Applied Materials Inc | AMAT | 47,255.97 | 0.21% | 1.71% | 7.50% | 9.27% | 0.0197% |
| Amcor PLC | AMCR | 13,777.69 | N/A | 5.64% | N/A | N/A | N/A |
| Advanced Micro Devices Inc | AMD | 57,084.30 | 0.26% | 0.00% | 18.00% | 18.00% | 0.0461% |
| AMETEK Inc | AME | 17,692.08 | 0.08% | 0.93% | 12.50% | 13.49% | 0.0107% |
| Amgen Inc | AMGN | 129,629.00 | 0.58% | 2.99% | 6.50% | 9.59% | 0.0557% |
| Ameriprise Financial Inc | AMP | 14,229.87 | 0.06% | 3.47% | 12.50% | 16.19% | 0.0103% |
| American Tower Corp | AMT | 110,376.60 | 0.50% | 1.84% | 11.50% | 13.45% | 0.0666% |
| Amazon.com Inc | AMZN | 1,011,285.00 | 4.54% | 0.00% | 39.00% | 39.00% | 1.7688% |
| Arista Networks Inc | ANET | 16,392.31 | 0.07% | 0.00% | 5.50% | 5.50% | 0.0040% |
| ANSYS Inc | ANSS | 20,950.82 | 0.09% | 0.00% | 13.00% | 13.00% | 0.0122% |
| Anthem Inc | ANTM | 62,476.79 | 0.28% | 1.54% | 14.00% | 15.65% | 0.0438% |
| Aon PLC | AON | 44,001.43 | 0.20% | 0.94% | 11.00% | 11.99% | 0.0237% |
| AO Smith Corp | AOS | 6,530.56 | 0.03% | 2.39% | 6.00% | 8.46% | 0.0025% |
| Apache Corp | APA | 2,850.25 | 0.01% | 1.32% | 46.00% | 47.62% | 0.0061% |
| Air Products & Chemicals Inc | APD | 47,613.49 | 0.21% | 2.48% | 10.50% | 13.11% | 0.0280% |
| Amphenol Corp | APH | 23,663.06 | 0.11% | 1.26% | 9.00% | 10.32% | 0.0109% |
| Aptiv PLC | APTV | 15,368.34 | 0.07% | 0.00% | 9.50% | 9.50% | 0.0065% |
| Alexandria Real Estate Equities Inc | ARE | 16,367.61 | 0.07% | 2.79% | 16.50% | 19.52% | 0.0143% |
| Atmos Energy Corp | ATO | 12,550.19 | 0.06% | 2.32% | 7.00% | 9.40% | 0.0053% |
| Activision Blizzard Inc | ATVI | 46,948.17 | 0.21% | 0.67% | 8.00% | 8.70% | 0.0183% |
| AvalonBay Communities Inc | AVB | 22,262.39 | 0.10% | 4.01% | 2.50% | 6.56% | 0.0065% |
| Broadcom Inc | AVGO | 104,178.90 | 0.47% | 4.98% | 17.00% | 22.40% | 0.1047% |
| Avery Dennison Corp | AVY | 9,211.90 | 0.04% | 2.25% | 9.50% | 11.86% | 0.0049% |
| American Water Works Co Inc | AWK | 22,664.91 | 0.10% | 1.69% | 8.50% | 10.26% | 0.0104% |
| American Express Co | AXP | 74,584.80 | 0.33% | 1.93% | 10.00% | 12.03% | 0.0402% |
| AutoZone Inc | AZO | 21,496.69 | 0.10% | 0.00% | 13.50% | 13.50% | 0.0130% |
| Boeing Co/The | BA | 82,674.45 | 0.37% | 0.00% | 16.00% | 16.00% | 0.0593% |
| Bank of America Corp | BAC | 207,207.70 | 0.93% | 3.24% | 10.50% | 13.91% | 0.1293% |
| Baxter International Inc | BAX | 42,918.63 | 0.19% | 1.04% | 10.50% | 11.59% | 0.0223% |
| Best Buy Co Inc | BBY | 16,757.00 | 0.08% | 3.41% | 10.50% | 14.09% | 0.0106% |
| Becton Dickinson and Co | BDX | 67,793.25 | 0.30% | 1.27% | 9.00% | 10.33% | 0.0314% |
| Franklin Resources Inc | BEN | 8,553.74 | 0.04% | 6.40% | 10.00% | 16.72% | 0.0064% |
| Brown-Forman Corp | BF/B | 29,212.47 | 0.13% | 1.14% | 11.00% | 12.20% | 0.0160% |
| Biogen Inc | BIIB | 57,653.21 | 0.26% | 0.00% | 9.50% | 9.50% | 0.0246% |
| Bank of New York Mellon Corp/The | BK | 32,109.35 | 0.14% | 3.48% | 7.00% | 10.60% | 0.0153% |
| Booking Holdings Inc | BKNG | 57,743.15 | 0.26% | 0.00% | 12.00% | 12.00% | 0.0311% |
| Baker Hughes Co | BKR | 8,385.00 | N/A | 5.58% | N/A | N/A | N/A |
| BlackRock Inc | BLK | 69,618.94 | 0.31% | 3.22% | 10.00% | 13.38% | 0.0418% |
| Ball Corp | BLL | 21,942.08 | 0.10% | 0.89% | 21.00% | 21.98% | 0.0216% |
| Bristol-Myers Squibb Co | BMY | 94,905.85 | 0.43% | 3.09% | 9.50% | 12.74% | 0.0542% |
| Broadridge Financial Solutions Inc | BR | 11,721.08 | 0.05% | 2.29% | 11.00% | 13.42% | 0.0071% |
| Berkshire Hathaway Inc | BRK/B | - | N/A | 0.00% | N/A | N/A | N/A |
| Boston Scientific Corp | BSX | 48,963.35 | 0.22% | 0.00% | 14.00% | 14.00% | 0.0307% |
| BorgWarner Inc | BWA | 5,269.60 | 0.02% | 2.66% | 6.00% | 8.74% | 0.0021% |
| Boston Properties Inc | BXP | 15,431.90 | 0.07% | 3.98% | 3.50% | 7.55% | 0.0052% |
| Citigroup Inc | C | 96,628.17 | 0.43% | 4.88% | 10.00% | 15.12% | 0.0655% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Conagra Brands Inc | CAG | 15,250.35 | 0.07% | 2.78% | 5.00% | 7.85% | 0.0054% |
| Cardinal Health Inc | CAH | 14,424.80 | 0.06% | 3.91% | 11.00% | 15.13% | 0.0098% |
| Carrier Global Corp | CARR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Caterpillar Inc | CAT | 70,408.63 | 0.32% | 3.23% | 10.50% | 13.90% | 0.0439% |
| Chubb Ltd | CB | 51,979.53 | 0.23% | 2.62% | 9.00% | 11.74% | 0.0274% |
| Cboe Global Markets Inc | CBOE | 10,589.78 | 0.05% | 1.51% | 12.50% | 14.10% | 0.0067% |
| CBRE Group Inc | CBRE | 15,196.27 | 0.07% | 0.00% | 10.50% | 10.50% | 0.0072% |
| Crown Castle International Corp | CCI | 65,461.75 | 0.29% | 3.15% | 15.50% | 18.89% | 0.0555% |
| Carnival Corp | CCL | 8,932.55 | 0.04% | 0.00% | 10.00% | 10.00% | 0.0040% |
| Cadence Design Systems Inc | CDNS | 20,104.78 | 0.09% | 0.00% | 12.50% | 12.50% | 0.0113% |
| CDW Corp/DE | CDW | 14,624.61 | 0.07% | 1.49% | 11.50% | 13.08% | 0.0086% |
| Celanese Corp | CE | 9,946.88 | 0.04% | 3.32% | 8.50% | 11.96% | 0.0053% |
| Cerner Corp | CERN | 20,847.30 | 0.09% | 1.08% | 9.50% | 10.63% | 0.0099% |
| CF Industries Holdings Inc | CF | 6,446.13 | 0.03% | 4.12% | 29.50% | 34.23% | 0.0099% |
| Citizens Financial Group Inc | CFG | 9,113.53 | 0.04% | 7.99% | 9.50% | 17.87% | 0.0073% |
| Church & Dwight Co Inc | CHD | 16,837.92 | 0.08% | 1.40% | 7.50% | 8.95% | 0.0068% |
| CH Robinson Worldwide Inc | CHRW | 9,841.77 | 0.04% | 2.80% | 8.00% | 10.91% | 0.0048% |
| Charter Communications Inc | CHTR | 97,413.70 | 0.44% | 0.00% | 33.50% | 33.50% | 0.1464% |
| Cigna Corp | CI | 69,539.20 | 0.31% | 0.02% | 14.00% | 14.02% | 0.0437% |
| Cincinnati Financial Corp | CINF | 13,248.47 | 0.06% | 2.96% | 11.00% | 14.12% | 0.0084% |
| Colgate-Palmolive Co | CL | 60,017.18 | 0.27% | 2.51% | 5.50% | 8.08% | 0.0217% |
| Clorox Co/The | CLX | 22,634.53 | 0.10% | 2.34% | 2.50% | 4.87% | 0.0049% |
| Comerica Inc | CMA | 4,759.37 | 0.02% | 8.24% | 8.00% | 16.57% | 0.0035% |
| Comcast Corp | CMCSA | 171,558.40 | 0.77% | 2.44% | 9.50% | 12.06% | 0.0928% |
| CME Group Inc | CME | 64,691.71 | 0.29% | 1.88% | 2.50% | 4.40% | 0.0128% |
| Chipotle Mexican Grill Inc | CMG | 20,125.71 | 0.09% | 0.00% | 17.50% | 17.50% | 0.0158% |
| Cummins Inc | CMI | 22,912.59 | 0.10% | 3.50% | 7.00% | 10.62% | 0.0109% |
| CMS Energy Corp | CMS | 17,213.51 | 0.08% | 2.74% | 7.50% | 10.34% | 0.0080% |
| Centene Corp | CNC | 27,040.38 | 0.12% | 0.00% | 13.00% | 13.00% | 0.0158% |
| CenterPoint Energy Inc | CNP | 8,447.71 | 0.04% | 3.57% | 6.50% | 10.19% | 0.0039% |
| Capital One Financial Corp | COF | 26,415.70 | 0.12% | 2.82% | 6.00% | 8.90% | 0.0105% |
| Cabot Oil & Gas Corp | COG | 7,828.06 | 0.04% | 2.08% | 40.50% | 43.00% | 0.0151% |
| Cooper Cos Inc/The | COO | 14,633.56 | 0.07% | 0.02% | 11.00% | 11.02% | 0.0072% |
| ConocoPhillips | COP | 38,708.09 | 0.17% | 4.71% | 37.00% | 42.58% | 0.0739% |
| Costco Wholesale Corp | COST | 135,123.10 | 0.61% | 0.94% | 11.00% | 11.99% | 0.0727% |
| Coty Inc | COTY | 4,471.74 | 0.02% | 8.50% | 4.50% | 13.19% | 0.0026% |
| Campbell Soup Co | CPB | 14,909.68 | 0.07% | 3.03% | 1.50% | 4.55% | 0.0030% |
| Capri Holdings Ltd | CPRI | 2,054.88 | 0.01% | 0.00% | 10.50% | 10.50% | 0.0010% |
| Copart Inc | CPRT | 16,817.19 | 0.08% | 0.00% | 16.00% | 16.00% | 0.0121% |
| salesforce.com Inc | CRM | 134,950.20 | 0.61% | 0.00% | 31.50% | 31.50% | 0.1906% |
| Cisco Systems Inc | CSCO | 177,019.30 | 0.79% | 3.45% | 7.00% | 10.57% | 0.0839% |
| CSX Corp | CSX | 49,130.88 | 0.22% | 1.64% | 12.00% | 13.74% | 0.0303% |
| Cintas Corp | CTAS | 20,015.84 | 0.09% | 1.51% | 15.00% | 16.62% | 0.0149% |
| CenturyLink Inc | CTL | 10,715.27 | 0.05% | 10.17% | 2.50% | 12.80% | 0.0061% |
| Cognizant Technology Solutions Corp | CTSH | 28,161.72 | 0.13% | 1.71% | 5.00% | 6.75% | 0.0085% |
| Corteva Inc | CTVA | 19,500.43 | N/A | 2.07% | N/A | N/A | N/A |
| Citrix Systems Inc | CTXS | 19,096.44 | 0.09% | 0.95% | 9.00% | 9.99% | 0.0086% |
| CVS Health Corp | CVS | 77,292.41 | 0.35% | 3.37% | 6.00% | 9.47% | 0.0328% |
| Chevron Corp | CVX | 161,828.80 | 0.73% | 6.00% | 13.50% | 19.91% | 0.1445% |
| Concho Resources Inc | CXO | 10,480.42 | 0.05% | 1.54% | 18.00% | 19.68% | 0.0092% |
| Dominion Energy Inc | D | 65,548.36 | 0.29% | 4.81% | 7.00% | 11.98% | 0.0352% |
| Delta Air Lines Inc | DAL | 15,023.84 | 0.07% | 0.00% | 9.50% | 9.50% | 0.0064% |
| DuPont de Nemours Inc | DD | 28,700.60 | N/A | 3.17% | N/A | N/A | N/A |
| Deere & Co | DE | 46,030.00 | 0.21% | 2.07% | 10.00% | 12.17% | 0.0251% |
| Discover Financial Services | DFS | 11,544.04 | 0.05% | 4.73% | 7.50% | 12.41% | 0.0064% |
| Dollar General Corp | DG | 43,083.41 | 0.19% | 0.85% | 12.00% | 12.90% | 0.0249% |
| Quest Diagnostics Inc | DGX | 11,682.72 | 0.05% | 2.55% | 9.00% | 11.66% | 0.0061% |
| DR Horton Inc | DHI | 14,522.72 | 0.07% | 1.77% | 7.00% | 8.83% | 0.0058% |
| Danaher Corp | DHR | 100,937.90 | 0.45% | 0.50% | 15.00% | 15.54% | 0.0703% |
| Walt Disney Co/The | DIS | 180,005.70 | 0.81% | 1.74% | 7.50% | 9.31% | 0.0751% |
| Discovery Inc | DISCA | 11,372.66 | 0.05% | 0.00% | 18.00% | 18.00% | 0.0092% |
| DISH Network Corp | DISH | 11,391.79 | 0.05% | 0.00% | -1.00% | -1.00% | -0.0005% |
| Digital Realty Trust Inc | DLR | 30,098.97 | 0.13% | 3.07% | 6.00% | 9.16% | 0.0124% |
| Dollar Tree Inc | DLTR | 18,751.37 | 0.08% | 0.00% | 10.00% | 10.00% | 0.0084% |
| Dover Corp | DOV | 13,015.83 | 0.06% | 2.19% | 9.50% | 11.79% | 0.0069% |
| Dow Inc | DOW | 25,796.72 | N/A | 8.19% | N/A | N/A | N/A |
| Duke Realty Corp | DRE | 11,992.80 | 0.05% | 2.87% | -1.00% | 1.86% | 0.0010% |
| Darden Restaurants Inc | DRI | 7,680.72 | 0.03% | 0.00% | 11.00% | 11.00% | 0.0038% |
| DTE Energy Co | DTE | 19,958.88 | 0.09% | 4.05% | 5.00% | 9.15% | 0.0082% |
| Duke Energy Corp | DUK | 62,671.50 | 0.28% | 4.48% | 6.00% | 10.61% | 0.0298% |
| DaVita Inc | DVA | 9,684.80 | 0.04% | 0.00% | 11.50% | 11.50% | 0.0050% |
| Devon Energy Corp | DVN | 3,638.85 | 0.02% | 5.10% | 16.50% | 22.02% | 0.0036% |
| DXC Technology Co | DXC | 4,004.87 | 0.02% | 5.32% | 10.00% | 15.59% | 0.0028% |
| Electronic Arts Inc | EA | 31,037.04 | 0.14% | 0.00% | 10.50% | 10.50% | 0.0146% |
| eBay Inc | EBAY | 26,275.96 | 0.12% | 1.94% | 10.00% | 12.04% | 0.0142% |
| Ecolab Inc | ECL | 49,227.44 | 0.22% | 1.10% | 8.50% | 9.65% | 0.0213% |
| Consolidated Edison Inc | ED | 27,915.39 | 0.13% | 3.69% | 3.50% | 7.25% | 0.0091% |
| Equifax Inc | EFX | 14,868.82 | 0.07% | 1.27% | 7.50% | 8.82% | 0.0059% |
| Edison International | EIX | 20,839.48 | 0.09% | 4.48% | 14.00% | 18.79% | 0.0176% |
| Estee Lauder Cos Inc/The | EL | 59,562.70 | 0.27% | 1.19% | 13.00% | 14.27% | 0.0381% |
| Eastman Chemical Co | EMN | 7,686.16 | 0.03% | 4.67% | 5.00% | 9.79% | 0.0034% |
| Emerson Electric Co | EMR | 31,833.10 | 0.14% | 3.84% | 9.00% | 13.01% | 0.0186% |
| EOG Resources Inc | EOG | 26,348.68 | 0.12% | 3.31% | 26.50% | 30.25% | 0.0357% |
| Equinix Inc | EQIX | 56,666.69 | 0.25% | 1.63% | 16.00% | 17.76% | 0.0451% |
| Equity Residential | EQR | 24,103.68 | 0.11% | 3.72% | -11.50% | -7.99% | -0.0086% |
| Eversource Energy | ES | 27,495.50 | 0.12% | 2.72% | 5.50% | 8.29% | 0.0102% |
| Essex Property Trust Inc | ESS | 15,426.17 | 0.07% | 3.58% | 1.00% | 4.60% | 0.0032% |
| E*TRADE Financial Corp | ETFC | 8,887.07 | 0.04% | 1.40% | 5.50% | 6.94% | 0.0028% |
| Eaton Corp PLC | ETN | 33,129.88 | 0.15% | 3.64% | 6.50% | 10.26% | 0.0152% |
| Entergy Corp | ETR | 20,018.36 | 0.09% | 3.74% | 3.00% | 6.80% | 0.0061% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Evergy Inc | EVRG | 13,793.37 | N/A | 3.42% | N/A | N/A | N/A |
| Edwards Lifesciences Corp | EW | 43,294.15 | 0.19% | 0.00% | 15.00% | 15.00% | 0.0291% |
| Exelon Corp | EXC | 36,575.07 | 0.16% | 4.07% | 8.00% | 12.23% | 0.0201% |
| Expeditors International of Washington I | EXPD | 12,337.51 | 0.06% | 1.38% | 7.50% | 8.93% | 0.0049% |
| Expedia Group Inc | EXPE | 8,809.42 | 0.04% | 2.25% | 24.00% | 26.52% | 0.0105% |
| Extra Space Storage Inc | EXR | 12,480.34 | 0.06% | 3.75% | 3.00% | 6.81% | 0.0038% |
| Ford Motor Co | F | 19,587.04 | 0.09% | 0.00% | 2.50% | 2.50% | 0.0022% |
| Diamondback Energy Inc | FANG | 5,959.40 | 0.03% | 4.00% | 17.00% | 21.34% | 0.0057% |
| Fastenal Co | FAST | 18,633.86 | 0.08% | 3.08% | 9.00% | 12.22% | 0.0102% |
| Facebook Inc | FB | 497,046.60 | 2.23% | 0.00% | 17.50% | 17.50% | 0.3901% |
| Fortune Brands Home & Security Inc | FBHS | 6,580.45 | 0.03% | 2.03% | 7.50% | 9.61% | 0.0028% |
| Freeport-McMoRan Inc | FCX | 11,651.53 | 0.05% | 0.00% | 19.50% | 19.50% | 0.0102% |
| FedEx Corp | FDX | 32,797.20 | 0.15% | 2.07% | 5.00% | 7.12% | 0.0105% |
| FirstEnergy Corp | FE | 23,372.39 | 0.10% | 3.63% | 7.00% | 10.76% | 0.0113% |
| F5 Networks Inc | FFIV | 7,351.08 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0033% |
| Fidelity National Information Services I | FIS | 76,608.78 | 0.34% | 1.12% | 23.50% | 24.75% | 0.0850% |
| Fiserv Inc | FISV | 66,970.30 | 0.30% | 0.00% | 15.00% | 15.00% | 0.0451% |
| Fifth Third Bancorp | FITB | 11,831.81 | 0.05% | 6.47% | 6.50% | 13.18% | 0.0070% |
| FLIR Systems Inc | FLIR | 4,683.63 | 0.02% | 2.04% | 9.00% | 11.13% | 0.0023% |
| Flowserve Corp | FLS | 3,751.46 | 0.02% | 2.78% | 12.50% | 15.45% | 0.0026% |
| FleetCor Technologies Inc | FLT | 19,116.52 | 0.09% | 0.00% | 16.50% | 16.50% | 0.0141% |
| FMC Corp | FMC | 10,700.50 | 0.05% | 2.17% | 11.00% | 13.29% | 0.0064% |
| Fox Corp | FOXA | 16,056.75 | N/A | 1.75% | N/A | N/A | N/A |
| First Republic Bank/CA | FRC | 15,733.23 | 0.07% | 0.81% | 10.50% | 11.35% | 0.0080% |
| Federal Realty Investment Trust | FRT | 6,063.68 | 0.03% | 5.28% | 1.50% | 6.82% | 0.0019% |
| TechnipFMC PLC | FTI | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Fortinet Inc | FTNT | 18,702.53 | 0.08% | 0.00% | 28.00% | 28.00% | 0.0235% |
| Fortive Corp | FTV | 20,356.85 | 0.09% | 0.46% | 8.00% | 8.48% | 0.0077% |
| General Dynamics Corp | GD | 39,791.86 | 0.18% | 3.20% | 7.00% | 10.31% | 0.0184% |
| General Electric Co | GE | 63,790.57 | 0.29% | 0.55% | 8.00% | 8.57% | 0.0245% |
| Gilead Sciences Inc | GILD | 94,937.34 | 0.43% | 3.63% | -1.50% | 2.10% | 0.0090% |
| General Mills Inc | GIS | 33,761.23 | 0.15% | 3.57% | 4.00% | 7.64% | 0.0116% |
| Globe Life Inc | GL | 8,101.62 | 0.04% | 1.00% | 9.00% | 10.05% | 0.0036% |
| Corning Inc | GLW | 15,674.34 | 0.07% | 4.28% | 13.50% | 18.07% | 0.0127% |
| General Motors Co | GM | 32,382.00 | 0.15% | 6.74% | 2.50% | 9.32% | 0.0135% |
| Alphabet Inc | GOOGL | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Genuine Parts Co | GPC | 10,642.71 | 0.05% | 4.31% | 7.00% | 11.46% | 0.0055% |
| Global Payments Inc | GPN | 44,820.59 | 0.20% | 0.52% | 20.50% | 21.07% | 0.0424% |
| Gap Inc/The | GPS | 2,912.35 | 0.01% | 0.00% | 3.00% | 3.00% | 0.0004% |
| Garmin Ltd | GRMN | 14,751.47 | 0.07% | 3.15% | 7.00% | 10.26% | 0.0068% |
| Goldman Sachs Group Inc/The | GS | 61,465.81 | 0.28% | 2.83% | 6.50% | 9.42% | 0.0260% |
| WW Grainger Inc | GWW | 14,517.24 | 0.07% | 2.13% | 8.00% | 10.22% | 0.0067% |
| Halliburton Co | HAL | 7,682.50 | 0.03% | 8.23% | 19.50% | 28.53% | 0.0098% |
| Hasbro Inc | HAS | 9,361.66 | 0.04% | 3.67% | 9.50% | 13.34% | 0.0056% |
| Huntington Bancshares Inc/OH | HBAN | 8,986.23 | 0.04% | 7.15% | 9.00% | 16.47% | 0.0066% |
| Hanesbrands Inc | HBI | 3,330.45 | 0.01% | 6.52% | 3.00% | 9.62% | 0.0014% |
| HCA Healthcare Inc | HCA | 36,572.37 | 0.16% | 1.59% | 10.50% | 12.17% | 0.0200% |
| Home Depot Inc/The | HD | 212,353.80 | 0.95% | 3.08% | 8.00% | 11.20% | 0.1067% |
| Hess Corp | HES | 11,857.08 | N/A | 2.55% | N/A | N/A | N/A |
| HollyFrontier Corp | HFC | 4,310.41 | 0.02% | 5.26% | 16.50% | 22.19% | 0.0043% |
| Hartford Financial Services Group Inc/Th | HIG | 13,970.04 | 0.06% | 3.36% | 12.50% | 16.07% | 0.0101% |
| Huntington Ingalls Industries Inc | HII | 8,013.04 | 0.04% | 2.11% | 6.00% | 8.17% | 0.0029% |
| Hilton Worldwide Holdings Inc | HLT | 23,277.24 | 0.10% | 0.00% | 17.00% | 17.00% | 0.0177% |
| Harley-Davidson Inc | HOG | 2,874.02 | 0.01% | 8.06% | 8.50% | 16.90% | 0.0022% |
| Hologic Inc | HOLX | 10,391.48 | 0.05% | 0.00% | 8.00% | 8.00% | 0.0037% |
| Honeywell International Inc | HON | 99,020.67 | 0.44% | 2.59% | 8.00% | 10.69% | 0.0475% |
| Helmerich & Payne Inc | HP | 2,043.62 | N/A | 5.33% | N/A | N/A | N/A |
| Hewlett Packard Enterprise Co | HPE | 13,227.39 | 0.06% | 4.89% | 7.50% | 12.57% | 0.0075% |
| HP Inc | HPQ | 22,526.76 | 0.10% | 4.58% | 10.50% | 15.32% | 0.0155% |
| H&R Block Inc | HRB | 2,802.42 | 0.01% | 7.35% | 7.00% | 14.61% | 0.0018% |
| Hormel Foods Corp | HRL | 25,457.35 | 0.11% | 2.07% | 8.50% | 10.66% | 0.0122% |
| Henry Schein Inc | HSIC | 7,659.38 | 0.03% | 0.00% | 6.50% | 6.50% | 0.0022% |
| Host Hotels & Resorts Inc | HST | 8,336.90 | 0.04% | 7.11% | -2.50% | 4.52% | 0.0017% |
| Hershey Co/The | HSY | 29,801.98 | 0.13% | 2.28% | 4.50% | 6.83% | 0.0091% |
| Humana Inc | HUM | 44,553.73 | 0.20% | 0.74% | 10.50% | 11.28% | 0.0225% |
| Howmet Aerospace Inc | HWM | 5,661.74 | 0.03% | 0.00% | 12.00% | 12.00% | 0.0030% |
| International Business Machines Corp | IBM | 105,823.30 | 0.47% | 5.53% | 1.50% | 7.07% | 0.0336% |
| Intercontinental Exchange Inc | ICE | 51,545.36 | 0.23% | 1.41% | 9.00% | 10.47% | 0.0242% |
| IDEXX Laboratories Inc | IDXX | 21,878.25 | 0.10% | 0.00% | 12.50% | 12.50% | 0.0123% |
| IDEX Corp | IEX | 11,481.59 | 0.05% | 1.33% | 7.50% | 8.88% | 0.0046% |
| International Flavors & Fragrances Inc | IFF | 12,946.59 | 0.06% | 2.56% | 7.50% | 10.16% | 0.0059% |
| Illumina Inc | ILMN | 41,305.53 | 0.19% | 0.00% | 12.00% | 12.00% | 0.0222% |
| Incyte Corp | INCY | 19,022.01 | 0.09% | 0.00% | 64.50% | 64.50% | 0.0550% |
| IHS Markit Ltd | INFO | 25,294.06 | 0.11% | 1.06% | 12.00% | 13.12% | 0.0149% |
| Intel Corp | INTC | 256,563.00 | 1.15% | 2.24% | 9.00% | 11.34% | 0.1305% |
| Intuit Inc | INTU | 64,068.95 | 0.29% | 0.91% | 14.50% | 15.48% | 0.0445% |
| International Paper Co | IP | 12,986.35 | 0.06% | 6.19% | 6.50% | 12.89% | 0.0075% |
| Interpublic Group of Cos Inc/The | IPG | 6,153.30 | 0.03% | 6.42% | 11.00% | 17.77% | 0.0049% |
| IPG Photonics Corp | IPGP | 6,378.38 | 0.03% | 0.00% | 9.50% | 9.50% | 0.0027% |
| IQVIA Holdings Inc | IQV | 24,594.39 | 0.11% | 0.00% | 9.50% | 9.50% | 0.0105% |
| Ingersoll Rand Inc | IR | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Iron Mountain Inc | IRM | 7,451.15 | 0.03% | 9.56% | 7.50% | 17.42% | 0.0058% |
| Intuitive Surgical Inc | ISRG | 59,013.80 | 0.26% | 0.00% | 14.00% | 14.00% | 0.0371% |
| Gartner Inc | IT | 9,358.92 | 0.04% | 0.00% | 12.50% | 12.50% | 0.0052% |
| Illinois Tool Works Inc | ITW | 51,038.32 | 0.23% | 2.70% | 8.00% | 10.81% | 0.0247% |
| Invesco Ltd | IVZ | 4,298.38 | 0.02% | 13.09% | 6.00% | 19.48% | 0.0038% |
| Jacobs Engineering Group Inc | J | 10,765.10 | 0.05% | 0.94% | 14.00% | 15.01% | 0.0072% |
| JB Hunt Transport Services Inc | JBHT | 10,533.10 | 0.05% | 1.10% | 7.50% | 8.64% | 0.0041% |
| Johnson Controls International plc | JCI | 22,394.22 | 0.10% | 3.55% | 5.50% | 9.15% | 0.0092% |
| Jack Henry & Associates Inc | JKHY | 12,993.82 | 0.06% | 1.02% | 12.00% | 13.08% | 0.0076% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Johnson & Johnson | JNJ | 376,911.50 | 1.69% | 2.65% | 11.50% | 14.30% | 0.2418% |
| Juniper Networks Inc | JNPR | 7,473.78 | 0.03% | 3.60% | 6.00% | 9.71% | 0.0033% |
| JPMorgan Chase & Co | JPM | 290,823.20 | 1.30% | 3.92% | 8.50% | 12.59% | 0.1642% |
| Nordstrom Inc | JWN | 2,948.80 | 0.01% | 0.00% | 5.00% | 5.00% | 0.0007% |
| Kellogg Co | K | 20,991.23 | 0.09% | 3.74% | 3.00% | 6.80% | 0.0064% |
| KeyCorp | KEY | 11,071.54 | 0.05% | 6.71% | 10.50% | 17.56% | 0.0087% |
| Keysight Technologies Inc | KEYS | 17,094.26 | 0.08% | 0.00% | 21.00% | 21.00% | 0.0161% |
| Kraft Heinz Co/The | KHC | 33,357.72 | 0.15% | 5.86% | -0.50% | 5.35% | 0.0080% |
| Kimco Realty Corp | KIM | 4,158.38 | 0.02% | 11.84% | 5.00% | 17.14% | 0.0032% |
| KLA Corp | KLAC | 23,887.35 | 0.11% | 2.23% | 11.50% | 13.86% | 0.0148% |
| Kimberly-Clark Corp | KMB | 45,296.57 | 0.20% | 3.23% | 7.00% | 10.34% | 0.0210% |
| Kinder Morgan Inc | KMI | 33,589.00 | 0.15% | 6.74% | 22.00% | 29.48% | 0.0444% |
| CarMax Inc | KMX | 10,355.12 | 0.05% | 0.00% | 10.50% | 10.50% | 0.0049% |
| Coca-Cola Co/The | KO | 204,669.60 | 0.92% | 3.43% | 6.50% | 10.04% | 0.0922% |
| Kroger Co/The | KR | 24,443.76 | 0.11% | 2.26% | 5.50% | 7.82% | 0.0086% |
| Kohl's Corp | KSS | 2,750.64 | 0.01% | 16.90% | 6.50% | 23.95% | 0.0030% |
| Kansas City Southern | KSU | 13,850.76 | 0.06% | 1.15% | 12.00% | 13.22% | 0.0082% |
| Loews Corp | L | 11,361.61 | 0.05% | 0.66% | 14.00% | 14.71% | 0.0075% |
| L Brands Inc | LB | 4,024.08 | 0.02% | 0.00% | -2.50% | -2.50% | -0.0005% |
| Leidos Holdings Inc | LDOS | 13,457.04 | 0.06% | 1.43% | 9.00% | 10.49% | 0.0063% |
| Leggett & Platt Inc | LEG | 3,791.89 | 0.02% | 5.56% | 8.00% | 13.78% | 0.0023% |
| Lennar Corp | LEN | 13,538.77 | 0.06% | 1.15% | 7.00% | 8.19% | 0.0050% |
| Laboratory Corp of America Holdings | LH | 13,748.98 | 0.06% | 0.00% | 8.00% | 8.00% | 0.0049% |
| L3Harris Technologies Inc | LHX | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Linde PLC | LIN | 100,547.00 | N/A | 2.06% | N/A | N/A | N/A |
| LKQ Corp | LKQ | 6,740.84 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0030% |
| Eli Lilly & Co | LLY | 140,009.50 | 0.63% | 2.02% | 10.00% | 12.12% | 0.0761% |
| Lockheed Martin Corp | LMT | 101,194.80 | 0.45% | 2.71% | 8.50% | 11.33% | 0.0514% |
| Lincoln National Corp | LNC | 6,403.51 | 0.03% | 5.16% | 9.50% | 14.91% | 0.0043% |
| Alliant Energy Corp | LNT | 12,552.53 | 0.06% | 2.97% | 5.50% | 8.55% | 0.0048% |
| Lowe's Cos Inc | LOW | 72,460.80 | 0.32% | 2.49% | 10.50% | 13.12% | 0.0426% |
| Lam Research Corp | LRCX | 38,001.74 | 0.17% | 1.72% | 10.00% | 11.81% | 0.0201% |
| Southwest Airlines Co | LUV | 17,803.90 | 0.08% | 2.10% | 10.00% | 12.21% | 0.0097% |
| Las Vegas Sands Corp | LVS | 35,540.23 | 0.16% | 6.79% | 7.50% | 14.54% | 0.0232% |
| Lamb Weston Holdings Inc | LW | 8,433.75 | 0.04% | 1.65% | 9.50% | 11.23% | 0.0042% |
| LyondellBasell Industries NV | LYB | 18,494.14 | 0.08% | 7.57% | 3.00% | 10.68% | 0.0089% |
| Live Nation Entertainment Inc | LYV | 8,069.92 | N/A | 0.00% | N/A | N/A | N/A |
| Mastercard Inc | MA | 273,659.50 | 1.23% | 0.59% | 16.00% | 16.64% | 0.2042% |
| Mid-America Apartment Communities Inc | MAA | 12,628.71 | 0.06% | 3.61% | 0.50% | 4.12% | 0.0023% |
| Marriott International Inc/MD | MAR | 26,979.06 | 0.12% | 0.00% | 11.50% | 11.50% | 0.0139% |
| Masco Corp | MAS | 10,897.22 | 0.05% | 1.47% | 7.00% | 8.52% | 0.0042% |
| McDonald's Corp | MCD | 132,460.80 | 0.59% | 2.87% | 8.00% | 10.98% | 0.0653% |
| Microchip Technology Inc | MCHP | 19,047.82 | 0.09% | 1.89% | 7.50% | 9.46% | 0.0081% |
| McKesson Corp | MCK | 23,286.12 | 0.10% | 1.25% | 9.00% | 10.31% | 0.0108% |
| Moody's Corp | MCO | 42,514.86 | 0.19% | 0.99% | 10.50% | 11.54% | 0.0220% |
| Mondelez International Inc | MDLZ | 74,318.96 | 0.33% | 2.32% | 8.00% | 10.41% | 0.0347% |
| Medtronic PLC | MDT | 133,113.20 | 0.60% | 2.22% | 7.50% | 9.80% | 0.0585% |
| MetLife Inc | MET | 30,636.36 | 0.14% | 5.26% | 7.50% | 12.96% | 0.0178% |
| MGM Resorts International | MGM | 7,547.22 | 0.03% | 4.00% | 14.00% | 18.28% | 0.0062% |
| Mohawk Industries Inc | MHK | 6,113.29 | N/A | 0.00% | N/A | N/A | N/A |
| McCormick & Co Inc/MD | MKC | 19,815.99 | 0.09% | 1.66% | 6.50% | 8.21% | 0.0073% |
| MarketAxess Holdings Inc | MKTX | 15,007.84 | 0.07% | 0.61% | 13.50% | 14.15% | 0.0095% |
| Martin Marietta Materials Inc | MLM | 12,278.45 | 0.06% | 1.13% | 10.50% | 11.69% | 0.0064% |
| Marsh & McLennan Cos Inc | MMC | 47,272.86 | 0.21% | 1.97% | 9.00% | 11.06% | 0.0234% |
| 3M Co | MMM | 85,676.84 | 0.38% | 3.95% | 4.50% | 8.54% | 0.0328% |
| Monster Beverage Corp | MNST | 32,341.42 | 0.15% | 0.00% | 11.50% | 11.50% | 0.0167% |
| Altria Group Inc | MO | 74,560.81 | 0.33% | 8.37% | 6.00% | 14.62% | 0.0489% |
| Mosaic Co/The | MOS | 4,593.06 | 0.02% | 1.86% | 22.00% | 24.06% | 0.0050% |
| Marathon Petroleum Corp | MPC | 15,801.50 | 0.07% | 9.54% | 9.00% | 18.97% | 0.0134% |
| Merck & Co Inc | MRK | 207,234.50 | 0.93% | 2.99% | 9.00% | 12.12% | 0.1127% |
| Marathon Oil Corp | MRO | 3,163.95 | N/A | 5.06% | N/A | N/A | N/A |
| Morgan Stanley | MS | 62,754.72 | 0.28% | 3.56% | 5.00% | 8.65% | 0.0243% |
| MSCI Inc | MSCI | 25,173.23 | 0.11% | 0.97% | 19.50% | 20.56% | 0.0232% |
| Microsoft Corp | MSFT | 1,256,805.00 | 5.64% | 1.24% | 15.50% | 16.84% | 0.9490% |
| Motorola Solutions Inc | MSI | 25,268.67 | 0.11% | 1.81% | 9.50% | 11.40% | 0.0129% |
| M&T Bank Corp | MTB | 14,056.60 | 0.06% | 4.09% | 9.50% | 13.78% | 0.0087% |
| Mettler-Toledo International Inc | MTD | 18,046.07 | 0.08% | 0.00% | 10.50% | 10.50% | 0.0085% |
| Micron Technology Inc | MU | 53,698.48 | 0.24% | 0.00% | 13.50% | 13.50% | 0.0325% |
| Maxim Integrated Products Inc | MXIM | 14,382.70 | 0.06% | 3.60% | 4.50% | 8.18% | 0.0053% |
| Mylan NV | MYL | 7,814.37 | 0.04% | 0.00% | 3.00% | 3.00% | 0.0011% |
| Noble Energy Inc | NBL | 3,453.31 | N/A | 6.65% | N/A | N/A | N/A |
| Norwegian Cruise Line Holdings Ltd | NCLH | 2,497.32 | 0.01% | 0.00% | 16.00% | 16.00% | 0.0018% |
| Nasdaq Inc | NDAQ | 17,191.24 | 0.08% | 1.81% | 6.00% | 7.86% | 0.0061% |
| NextEra Energy Inc | NEE | 114,181.50 | 0.51% | 2.42% | 10.00% | 12.54% | 0.0642% |
| Newmont Corp | NEM | 40,828.24 | 0.18% | 1.98% | 11.00% | 13.09% | 0.0240% |
| Netflix Inc | NFLX | 162,850.00 | 0.73% | 0.00% | 32.00% | 32.00% | 0.2337% |
| NiSource Inc | NI | 9,511.70 | 0.04% | 3.30% | 14.00% | 17.53% | 0.0075% |
| NIKE Inc | NKE | 132,641.50 | 0.59% | 1.15% | 17.50% | 18.75% | 0.1115% |
| NortonLifeLock Inc | NLOK | 12,022.12 | 0.05% | 2.55% | 5.00% | 7.61% | 0.0041% |
| Nielsen Holdings PLC | NLSN | 5,306.64 | 0.02% | 1.61% | 41.00% | 42.94% | 0.0102% |
| Northrop Grumman Corp | NOC | 55,264.89 | 0.25% | 1.60% | 10.00% | 11.68% | 0.0289% |
| National Oilwell Varco Inc | NOV | 4,506.73 | N/A | 1.71% | N/A | N/A | N/A |
| ServiceNow Inc | NOW | 51,674.59 | N/A | 0.00% | N/A | N/A | N/A |
| NRG Energy Inc | NRG | 7,420.99 | N/A | 4.08% | N/A | N/A | N/A |
| Norfolk Southern Corp | NSC | 40,999.16 | 0.18% | 2.37% | 13.00% | 15.52% | 0.0285% |
| NetApp Inc | NTAP | 9,097.56 | 0.04% | 5.12% | 10.00% | 15.38% | 0.0063% |
| Northern Trust Corp | NTRS | 17,666.72 | 0.08% | 3.36% | 7.50% | 10.99% | 0.0087% |
| Nucor Corp | NUE | 11,801.50 | 0.05% | 4.12% | 11.00% | 15.35% | 0.0081% |
| NVIDIA Corp | NVDA | 163,373.40 | 0.73% | 0.24% | 10.00% | 10.25% | 0.0751% |
| NVR Inc | NVR | 10,661.58 | 0.05% | 0.00% | 9.50% | 9.50% | 0.0045% |

| | | [4] | [5] | [6] | [7] | [8] | [9] |
|---|---|---|---|---|---|---|---|
| Company | Ticker | Market Capitalization ($ mil) | Weight in Index | Estimated Dividend Yield | Long-Term Growth Est. | DCF Result | Weighted DCF Result |
| Newell Brands Inc | NWL | 5,704.55 | 0.03% | 6.83% | 6.00% | 13.03% | 0.0033% |
| News Corp | NWSA | 5,264.68 | N/A | 2.24% | N/A | N/A | N/A |
| Realty Income Corp | O | 16,137.81 | 0.07% | 5.33% | 6.50% | 12.00% | 0.0087% |
| Old Dominion Freight Line Inc | ODFL | 16,571.93 | 0.07% | 0.46% | 9.00% | 9.48% | 0.0070% |
| ONEOK Inc | OKE | 10,925.86 | 0.05% | 14.75% | 16.00% | 31.93% | 0.0156% |
| Omnicom Group Inc | OMC | 11,868.86 | 0.05% | 5.12% | 6.50% | 11.79% | 0.0063% |
| Oracle Corp | ORCL | 164,782.90 | 0.74% | 1.84% | 10.00% | 11.93% | 0.0882% |
| O'Reilly Automotive Inc | ORLY | 25,712.39 | 0.12% | 0.00% | 12.00% | 12.00% | 0.0138% |
| Otis Worldwide Corp | OTIS | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Occidental Petroleum Corp | OXY | 13,900.01 | 0.06% | 2.83% | 20.50% | 23.62% | 0.0147% |
| Paycom Software Inc | PAYC | 11,680.15 | 0.05% | 0.00% | 26.00% | 26.00% | 0.0136% |
| Paychex Inc | PAYX | 23,337.02 | 0.10% | 4.18% | 10.50% | 14.90% | 0.0156% |
| People's United Financial Inc | PBCT | 4,968.32 | 0.02% | 6.43% | 4.00% | 10.56% | 0.0024% |
| PACCAR Inc | PCAR | 22,975.22 | 0.10% | 4.21% | 6.00% | 10.34% | 0.0107% |
| Healthpeak Properties Inc | PEAK | 12,739.59 | 0.06% | 5.55% | -15.50% | -10.38% | -0.0059% |
| Public Service Enterprise Group Inc | PEG | 25,633.44 | 0.11% | 3.85% | 6.00% | 9.97% | 0.0115% |
| PepsiCo Inc | PEP | 184,460.50 | 0.83% | 3.08% | 6.00% | 9.17% | 0.0759% |
| Pfizer Inc | PFE | 191,476.40 | 0.86% | 4.39% | 8.50% | 13.08% | 0.1123% |
| Principal Financial Group Inc | PFG | 8,462.32 | 0.04% | 7.36% | 5.50% | 13.06% | 0.0050% |
| Procter & Gamble Co/The | PG | 284,234.10 | 1.27% | 2.59% | 8.50% | 11.20% | 0.1428% |
| Progressive Corp/The | PGR | 45,487.73 | 0.20% | 0.51% | 13.50% | 14.04% | 0.0287% |
| Parker-Hannifin Corp | PH | 18,149.25 | 0.08% | 2.49% | 9.00% | 11.60% | 0.0094% |
| PulteGroup Inc | PHM | 6,896.40 | 0.03% | 1.96% | 7.50% | 9.53% | 0.0029% |
| Packaging Corp of America | PKG | 8,314.50 | 0.04% | 3.87% | 4.00% | 7.95% | 0.0030% |
| PerkinElmer Inc | PKI | 8,655.58 | 0.04% | 0.36% | 10.00% | 10.38% | 0.0040% |
| Prologis Inc | PLD | 54,448.26 | 0.24% | 2.74% | 6.00% | 8.82% | 0.0215% |
| Philip Morris International Inc | PM | 116,163.10 | 0.52% | 6.27% | 5.50% | 11.94% | 0.0622% |
| PNC Financial Services Group Inc/The | PNC | 43,083.50 | 0.19% | 4.62% | 8.00% | 12.80% | 0.0247% |
| Pentair PLC | PNR | 5,501.50 | 0.02% | 2.33% | 6.00% | 8.40% | 0.0021% |
| Pinnacle West Capital Corp | PNW | 8,867.83 | 0.04% | 4.08% | 4.00% | 8.16% | 0.0032% |
| PPG Industries Inc | PPG | 22,000.73 | 0.10% | 2.19% | 6.00% | 8.26% | 0.0081% |
| PPL Corp | PPL | 19,802.29 | 0.09% | 6.43% | 2.50% | 9.01% | 0.0080% |
| Perrigo Co PLC | PRGO | 6,648.49 | 0.03% | 1.90% | 3.50% | 5.43% | 0.0016% |
| Prudential Financial Inc | PRU | 21,943.73 | 0.10% | 8.00% | 7.00% | 15.28% | 0.0150% |
| Public Storage | PSA | 34,664.26 | 0.16% | 4.02% | 3.50% | 7.59% | 0.0118% |
| Phillips 66 | PSX | 28,305.60 | 0.13% | 6.28% | 9.00% | 15.56% | 0.0198% |
| PVH Corp | PVH | 3,462.11 | 0.02% | 0.00% | 9.00% | 9.00% | 0.0014% |
| Quanta Services Inc | PWR | 4,811.80 | 0.02% | 0.59% | 15.00% | 15.63% | 0.0034% |
| Pioneer Natural Resources Co | PXD | 13,299.47 | 0.06% | 2.74% | 35.00% | 38.22% | 0.0228% |
| PayPal Holdings Inc | PYPL | 123,340.40 | 0.55% | 0.00% | 20.00% | 20.00% | 0.1106% |
| QUALCOMM Inc | QCOM | 83,816.20 | 0.38% | 3.55% | 9.50% | 13.22% | 0.0497% |
| Qorvo Inc | QRVO | 10,071.52 | 0.05% | 0.00% | 53.00% | 53.00% | 0.0239% |
| Royal Caribbean Cruises Ltd | RCL | 7,842.57 | 0.04% | 8.31% | 12.50% | 21.33% | 0.0075% |
| Everest Re Group Ltd | RE | 8,058.57 | 0.04% | 3.13% | 9.50% | 12.78% | 0.0046% |
| Regency Centers Corp | REG | 6,865.64 | 0.03% | 5.82% | 13.50% | 19.71% | 0.0061% |
| Regeneron Pharmaceuticals Inc | REGN | 56,498.21 | 0.25% | 0.00% | 6.00% | 6.00% | 0.0152% |
| Regions Financial Corp | RF | 9,679.12 | 0.04% | 6.33% | 10.00% | 16.65% | 0.0072% |
| Robert Half International Inc | RHI | 4,806.42 | 0.02% | 3.33% | 8.00% | 11.46% | 0.0025% |
| Raymond James Financial Inc | RJF | 9,253.21 | 0.04% | 2.25% | 6.50% | 8.82% | 0.0037% |
| Ralph Lauren Corp | RL | 5,612.99 | 0.03% | 3.61% | 8.00% | 11.75% | 0.0030% |
| ResMed Inc | RMD | 22,435.98 | 0.10% | 1.01% | 14.50% | 15.58% | 0.0157% |
| Rockwell Automation Inc | ROK | 19,498.36 | 0.09% | 2.44% | 7.00% | 9.53% | 0.0083% |
| Rollins Inc | ROL | 11,758.44 | 0.05% | 1.34% | 11.00% | 12.41% | 0.0065% |
| Roper Technologies Inc | ROP | 33,112.13 | 0.15% | 0.64% | 8.00% | 8.67% | 0.0129% |
| Ross Stores Inc | ROST | 32,002.61 | 0.14% | 1.28% | 9.50% | 10.84% | 0.0156% |
| Republic Services Inc | RSG | 27,642.19 | 0.12% | 2.15% | 10.00% | 12.26% | 0.0152% |
| Raytheon Technologies Corp | RTX | 54,126.60 | 0.24% | 4.70% | 8.00% | 12.89% | 0.0313% |
| SBA Communications Corp | SBAC | 34,013.16 | 0.15% | 0.62% | 31.50% | 32.22% | 0.0491% |
| Starbucks Corp | SBUX | 84,058.98 | 0.38% | 2.43% | 13.50% | 16.09% | 0.0607% |
| Charles Schwab Corp/The | SCHW | 46,916.10 | 0.21% | 1.97% | 6.50% | 8.53% | 0.0180% |
| Sealed Air Corp | SEE | 4,417.53 | 0.02% | 2.24% | 26.00% | 28.53% | 0.0057% |
| Sherwin-Williams Co/The | SHW | 44,994.84 | 0.20% | 1.10% | 8.50% | 9.65% | 0.0195% |
| SVB Financial Group | SIVB | 8,691.31 | 0.04% | 0.00% | 15.00% | 15.00% | 0.0058% |
| JM Smucker Co/The | SJM | 13,015.50 | 0.06% | 3.11% | 3.00% | 6.16% | 0.0036% |
| Schlumberger Ltd | SLB | 23,924.42 | 0.11% | 11.57% | 15.00% | 27.44% | 0.0294% |
| SL Green Realty Corp | SLG | 4,128.48 | 0.02% | 7.27% | 0.50% | 7.79% | 0.0014% |
| Snap-on Inc | SNA | 6,385.17 | 0.03% | 3.71% | 5.50% | 9.31% | 0.0027% |
| Synopsys Inc | SNPS | 20,855.55 | 0.09% | 0.00% | 12.50% | 12.50% | 0.0117% |
| Southern Co/The | SO | 61,278.14 | 0.27% | 4.40% | 4.00% | 8.49% | 0.0233% |
| Simon Property Group Inc | SPG | 19,439.76 | N/A | 13.35% | N/A | N/A | N/A |
| S&P Global Inc | SPGI | 63,913.05 | 0.29% | 1.03% | 11.00% | 12.09% | 0.0346% |
| Sempra Energy | SRE | 35,603.45 | 0.16% | 3.44% | 11.00% | 14.63% | 0.0234% |
| STERIS PLC | STE | 12,655.06 | 0.06% | 0.99% | 9.50% | 10.54% | 0.0060% |
| State Street Corp | STT | 20,750.27 | 0.09% | 3.65% | 5.50% | 9.25% | 0.0086% |
| Seagate Technology PLC | STX | 13,314.95 | 0.06% | 5.19% | 3.00% | 8.27% | 0.0049% |
| Constellation Brands Inc | STZ | 30,105.51 | 0.14% | 1.90% | 7.50% | 9.47% | 0.0128% |
| Stanley Black & Decker Inc | SWK | 20,234.17 | 0.09% | 2.47% | 8.00% | 10.57% | 0.0096% |
| Skyworks Solutions Inc | SWKS | 15,856.50 | 0.07% | 1.89% | 10.00% | 11.98% | 0.0085% |
| Synchrony Financial | SYF | 10,994.51 | 0.05% | 5.23% | 9.50% | 14.98% | 0.0074% |
| Stryker Corp | SYK | 66,055.39 | 0.30% | 1.30% | 12.00% | 13.38% | 0.0396% |
| Sysco Corp | SYY | 24,042.83 | 0.11% | 3.81% | 9.50% | 13.49% | 0.0145% |
| AT&T Inc | T | 216,838.60 | 0.97% | 6.99% | 5.50% | 12.68% | 0.1233% |
| Molson Coors Beverage Co | TAP | 9,867.61 | 0.04% | 5.00% | 5.00% | 10.13% | 0.0045% |
| TransDigm Group Inc | TDG | 17,604.38 | 0.08% | 0.00% | 15.50% | 15.50% | 0.0122% |
| TE Connectivity Ltd | TEL | 23,095.73 | 0.10% | 2.66% | 5.50% | 8.23% | 0.0085% |
| Truist Financial Corp | TFC | 43,888.82 | 0.20% | 5.63% | 11.50% | 17.45% | 0.0344% |
| Teleflex Inc | TFX | 14,887.87 | 0.07% | 0.42% | 14.00% | 14.45% | 0.0096% |
| Target Corp | TGT | 53,013.72 | 0.24% | 2.52% | 9.50% | 12.14% | 0.0289% |
| Tiffany & Co | TIF | 15,511.46 | 0.07% | 1.84% | 10.50% | 12.44% | 0.0087% |
| TJX Cos Inc/The | TJX | 59,088.37 | 0.27% | 2.12% | 13.50% | 15.76% | 0.0418% |

| Company | Ticker | [4] Market Capitalization ($ mil) | [5] Weight in Index | [6] Estimated Dividend Yield | [7] Long-Term Growth Est. | [8] DCF Result | [9] Weighted DCF Result |
|---|---|---|---|---|---|---|---|
| Thermo Fisher Scientific Inc | TMO | 133,311.70 | 0.60% | 0.29% | 11.00% | 11.31% | 0.0676% |
| T-Mobile US Inc | TMUS | 74,422.20 | 0.33% | 0.00% | 14.00% | 14.00% | 0.0467% |
| Tapestry Inc | TPR | 4,131.72 | 0.02% | 0.00% | 10.50% | 10.50% | 0.0019% |
| T Rowe Price Group Inc | TROW | 24,763.41 | 0.11% | 3.41% | 10.00% | 13.58% | 0.0151% |
| Travelers Cos Inc/The | TRV | 26,812.17 | 0.12% | 3.13% | 7.50% | 10.75% | 0.0129% |
| Tractor Supply Co | TSCO | 10,717.57 | 0.05% | 1.72% | 9.50% | 11.30% | 0.0054% |
| Tyson Foods Inc | TSN | 21,319.65 | 0.10% | 2.95% | 7.00% | 10.05% | 0.0096% |
| Trane Technologies PLC | TT | N/A | N/A | 0.00% | N/A | N/A | N/A |
| Take-Two Interactive Software Inc | TTWO | 13,499.99 | 0.06% | 0.00% | 20.50% | 20.50% | 0.0124% |
| Twitter Inc | TWTR | 21,720.19 | N/A | 0.00% | N/A | N/A | N/A |
| Texas Instruments Inc | TXN | 102,682.00 | 0.46% | 3.27% | 4.50% | 7.84% | 0.0361% |
| Textron Inc | TXT | 6,365.47 | 0.03% | 0.29% | 8.50% | 8.80% | 0.0025% |
| Under Armour Inc | UAA | 4,404.73 | 0.02% | 0.00% | 17.50% | 17.50% | 0.0035% |
| United Airlines Holdings Inc | UAL | 6,977.20 | 0.03% | 0.00% | 10.00% | 10.00% | 0.0031% |
| UDR Inc | UDR | 10,652.61 | 0.05% | 3.54% | 5.00% | 8.63% | 0.0041% |
| Universal Health Services Inc | UHS | 9,370.40 | 0.04% | 0.75% | 11.00% | 11.79% | 0.0050% |
| Ulta Beauty Inc | ULTA | 11,489.25 | 0.05% | 0.00% | 13.00% | 13.00% | 0.0067% |
| UnitedHealth Group Inc | UNH | 253,902.90 | 1.14% | 1.61% | 12.00% | 13.71% | 0.1561% |
| Unum Group | UNM | 3,086.67 | 0.01% | 7.50% | 7.50% | 15.28% | 0.0021% |
| Union Pacific Corp | UNP | 103,552.10 | 0.46% | 2.59% | 11.50% | 14.24% | 0.0661% |
| United Parcel Service Inc | UPS | 84,722.30 | 0.38% | 4.09% | 7.00% | 11.23% | 0.0427% |
| United Rentals Inc | URI | 8,301.77 | 0.04% | 0.00% | 9.50% | 9.50% | 0.0035% |
| US Bancorp | USB | 54,692.63 | 0.25% | 4.83% | 5.00% | 9.95% | 0.0244% |
| Visa Inc | V | 343,757.10 | 1.54% | 0.72% | 18.00% | 18.78% | 0.2896% |
| Varian Medical Systems Inc | VAR | 10,451.36 | 0.05% | 0.00% | 13.50% | 13.50% | 0.0063% |
| VF Corp | VFC | 22,878.68 | 0.10% | 3.31% | 7.00% | 10.43% | 0.0107% |
| ViacomCBS Inc | VIAC | 5,923.13 | 0.03% | 6.08% | 12.00% | 18.44% | 0.0049% |
| Valero Energy Corp | VLO | 21,119.47 | 0.09% | 7.60% | 10.00% | 17.98% | 0.0170% |
| Vulcan Materials Co | VMC | 14,953.95 | 0.07% | 1.20% | 13.00% | 14.28% | 0.0096% |
| Vornado Realty Trust | VNO | 7,725.61 | 0.03% | 6.52% | -5.00% | 1.36% | 0.0005% |
| Verisk Analytics Inc | VRSK | 24,335.05 | 0.11% | 0.73% | 10.50% | 11.27% | 0.0123% |
| VeriSign Inc | VRSN | 22,549.34 | 0.10% | 0.00% | 11.00% | 11.00% | 0.0111% |
| Vertex Pharmaceuticals Inc | VRTX | 64,228.78 | 0.29% | 0.00% | 46.00% | 46.00% | 0.1325% |
| Ventas Inc | VTR | 10,750.65 | 0.05% | 10.51% | 1.50% | 12.09% | 0.0058% |
| Verizon Communications Inc | VZ | 239,048.30 | 1.07% | 4.27% | 4.50% | 8.87% | 0.0951% |
| Westinghouse Air Brake Technologies Corp | WAB | 10,069.95 | 0.05% | 0.91% | 12.50% | 13.47% | 0.0061% |
| Waters Corp | WAT | 12,768.14 | 0.06% | 0.00% | 10.50% | 10.50% | 0.0060% |
| Walgreens Boots Alliance Inc | WBA | 38,267.80 | 0.17% | 4.25% | 6.50% | 10.89% | 0.0187% |
| Western Digital Corp | WDC | 13,556.66 | 0.06% | 4.41% | 0.50% | 4.92% | 0.0030% |
| WEC Energy Group Inc | WEC | 29,083.01 | 0.13% | 2.79% | 6.00% | 8.87% | 0.0116% |
| Welltower Inc | WELL | 19,794.05 | 0.09% | 6.75% | 9.50% | 16.57% | 0.0147% |
| Wells Fargo & Co | WFC | 129,269.60 | 0.58% | 6.87% | 5.50% | 12.56% | 0.0728% |
| Whirlpool Corp | WHR | 6,279.84 | 0.03% | 4.82% | 5.00% | 9.94% | 0.0028% |
| Willis Towers Watson PLC | WLTW | 24,457.53 | 0.11% | 1.43% | 17.50% | 19.06% | 0.0209% |
| Waste Management Inc | WM | 40,558.18 | 0.18% | 2.28% | 7.00% | 9.36% | 0.0170% |
| Williams Cos Inc/The | WMB | 18,592.08 | 0.08% | 10.43% | 13.00% | 24.11% | 0.0201% |
| Walmart Inc | WMT | 345,903.80 | 1.55% | 1.77% | 7.50% | 9.34% | 0.1448% |
| WR Berkley Corp | WRB | 10,128.01 | 0.05% | 0.80% | 10.00% | 10.84% | 0.0049% |
| Westrock Co | WRK | 7,930.30 | 0.04% | 6.13% | 6.50% | 12.83% | 0.0046% |
| Western Union Co/The | WU | 8,468.68 | 0.04% | 4.44% | 6.50% | 11.08% | 0.0042% |
| Weyerhaeuser Co | WY | 14,499.08 | 0.07% | 6.99% | 10.50% | 17.86% | 0.0116% |
| Wynn Resorts Ltd | WYNN | 7,415.63 | 0.03% | 5.79% | 14.50% | 20.71% | 0.0069% |
| Xcel Energy Inc | XEL | 32,941.05 | 0.15% | 2.74% | 5.50% | 8.32% | 0.0123% |
| Xilinx Inc | XLNX | 21,026.73 | 0.09% | 1.75% | 6.00% | 7.80% | 0.0074% |
| Exxon Mobil Corp | XOM | 185,660.90 | 0.83% | 8.07% | 9.00% | 17.43% | 0.1452% |
| DENTSPLY SIRONA Inc | XRAY | 8,798.63 | 0.04% | 1.01% | 6.00% | 7.04% | 0.0028% |
| Xerox Holdings Corp | XRX | 4,098.32 | 0.02% | 5.19% | 9.50% | 14.94% | 0.0027% |
| Xylem Inc/NY | XYL | 12,445.87 | 0.06% | 1.51% | 8.50% | 10.07% | 0.0056% |
| Yum! Brands Inc | YUM | 22,837.11 | 0.10% | 2.49% | 11.00% | 13.63% | 0.0140% |
| Zimmer Biomet Holdings Inc | ZBH | 22,879.17 | 0.10% | 0.86% | 4.50% | 5.38% | 0.0055% |
| Zebra Technologies Corp | ZBRA | 10,628.34 | 0.05% | 0.00% | 15.00% | 15.00% | 0.0071% |
| Zions Bancorp NA | ZION | 4,859.28 | 0.02% | 4.62% | 9.50% | 14.34% | 0.0031% |
| Zoetis Inc | ZTS | 60,510.94 | 0.27% | 0.63% | 12.00% | 12.67% | 0.0344% |
| Total Market Capitalization: | | 22,297,457.29 | | | | | 14.82% |

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg and Value Line Beta Coefficients

| Company | Ticker | [1] Bloomberg | [2] Value Line |
|---|---|---|---|
| ALLETE, Inc. | ALE | 0.939 | 0.60 |
| Alliant Energy Corporation | LNT | 1.003 | 0.55 |
| Ameren Corporation | AEE | 0.922 | 0.50 |
| American Electric Power Company, Inc. | AEP | 0.983 | 0.50 |
| Avangrid, Inc. | AGR | 0.755 | 0.40 |
| Avista | AVA | 0.927 | 0.60 |
| CMS Energy Corporation | CMS | 0.940 | 0.50 |
| DTE Energy Company | DTE | 1.097 | 0.50 |
| Evergy, Inc | EVRG | 1.043 | 0.66 |
| Hawaiian Electric Industries, Inc. | HE | 0.768 | 0.55 |
| NextEra Energy, Inc. | NEE | 0.912 | 0.50 |
| NorthWestern Corporation | NWE | 1.184 | 0.60 |
| OGE Energy Corp. | OGE | 1.163 | 0.70 |
| Otter Tail Corporation | OTTR | 0.973 | 0.70 |
| Pinnacle West Capital Corporation | PNW | 1.051 | 0.50 |
| PNM Resources, Inc. | PNM | 1.269 | 0.60 |
| Portland General Electric Company | POR | 0.986 | 0.55 |
| Southern Company | SO | 1.050 | 0.50 |
| WEC Energy Group, Inc. | WEC | 0.978 | 0.50 |
| Xcel Energy Inc. | XEL | 0.958 | 0.45 |
| Mean | | 0.995 | 0.548 |

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

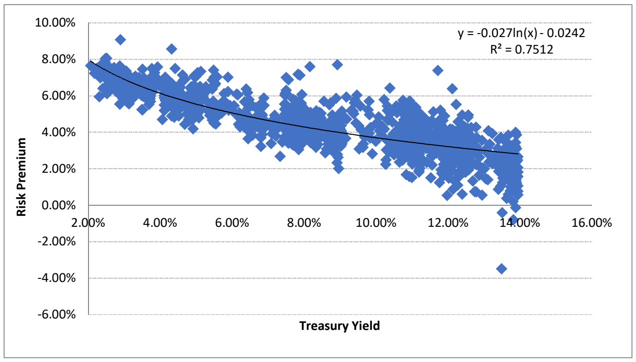
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|
| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM Result | |
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg MRP | Value Line MRP | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury [9] | 1.37% | 0.995 | 11.56% | 13.45% | 12.87% | 14.75% | 12.89% | 14.77% |
| Near-Term Projected 30-Year Treasury [10] | 1.75% | 0.995 | 11.56% | 13.45% | 13.25% | 15.13% | 13.27% | 15.15% |
| Long-Term Projected 30-Year Treasury [11] | 3.45% | 0.995 | 11.56% | 13.45% | 14.95% | 16.83% | 14.97% | 16.85% |
| Mean | | | | | 13.06% | 14.94% | 13.08% | 14.96% |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Ex-Ante Market Risk Premium | | CAPM Result | | ECAPM Result | |
| | Risk-Free Rate | Average Beta Coefficient | Bloomberg Market DCF Derived | Value Line Market DCF Derived | Bloomberg MRP | Value Line MRP | Bloomberg Market DCF Derived | Value Line Market DCF Derived |
| ***PROXY GROUP AVERAGE VALUE LINE AVERAGE BETA COEFFICIENT*** | | | | | | | | |
| Current 30-Year Treasury [9] | 1.37% | 0.548 | 11.56% | 13.45% | 7.70% | 8.74% | 9.01% | 10.26% |
| Near-Term Projected 30-Year Treasury [10] | 1.75% | 0.548 | 11.56% | 13.45% | 8.08% | 9.11% | 9.39% | 10.64% |
| Long-Term Projected 30-Year Treasury [11] | 3.45% | 0.548 | 11.56% | 13.45% | 9.78% | 10.81% | 11.09% | 12.34% |
| Mean | | | | | 7.89% | 8.93% | 9.20% | 10.45% |

Notes:
[1] *See Notes [9], [10], [11]*
[2] Source: Rebuttal Exhibit DWD-3
[3] Source: Rebuttal Exhibit DWD-2
[4] Source: Rebuttal Exhibit DWD-2
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Equals Col. [1] + 0.25 x Col. [3] + 0.75 x Col. [2] x Col. [3]
[8] Equals Col. [1] + 0.25 x Col. [4] + 0.75 x Col. [2] x Col. [4]
[9] Source: Bloomberg Professional
[10] Source: Blue Chip Financial Forecasts, Vol. 39, No. 4, April 1, 2020, at 2.
[11] Source: Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14.

Bond Yield Plus Risk Premium

| | [1] | [2] | [3] | [4] | [5] |
|---|---|---|---|---|---|
| | Constant | Slope | 30-Year Treasury Yield | Risk Premium | Return on Equity |
| | -2.42% | -2.66% | | | |
| Current 30-Year Treasury | | | 1.37% | 8.98% | 10.35% |
| Near-Term Projected 30-Year Treasury | | | 1.75% | 8.33% | 10.08% |
| Long-Term Projected 30-Year Treasury | | | 3.45% | 6.52% | 9.97% |




Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional,
Near Term Projected = Blue Chip Financial Forecasts, Vol. 39, No. 4, April 1, 2020, at 2.
Long Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2019, at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Global Market Intelligence
[7] Source: S&P Global Market Intelligence
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

| [6] Date of Electric Rate Case | [7] Return on Equity | [8] 30-Year Treasury Yield | [9] Risk Premium |
|---|---|---|---|
| 1/1/1980 | 14.50% | 9.36% | 5.14% |
| 1/7/1980 | 14.39% | 9.39% | 5.00% |
| 1/9/1980 | 15.00% | 9.40% | 5.60% |
| 1/14/1980 | 15.17% | 9.42% | 5.75% |
| 1/17/1980 | 13.93% | 9.44% | 4.49% |
| 1/23/1980 | 15.50% | 9.47% | 6.03% |
| 1/30/1980 | 13.86% | 9.52% | 4.34% |
| 1/31/1980 | 12.61% | 9.53% | 3.08% |
| 2/6/1980 | 13.71% | 9.58% | 4.13% |
| 2/13/1980 | 12.80% | 9.64% | 3.16% |
| 2/14/1980 | 13.00% | 9.65% | 3.35% |
| 2/19/1980 | 13.50% | 9.68% | 3.82% |
| 2/27/1980 | 13.75% | 9.78% | 3.97% |
| 2/29/1980 | 13.75% | 9.81% | 3.94% |
| 2/29/1980 | 14.00% | 9.81% | 4.19% |
| 2/29/1980 | 14.77% | 9.81% | 4.96% |
| 3/7/1980 | 12.70% | 9.90% | 2.80% |
| 3/14/1980 | 13.50% | 9.97% | 3.53% |
| 3/26/1980 | 14.16% | 10.11% | 4.05% |
| 3/27/1980 | 14.24% | 10.12% | 4.12% |
| 3/28/1980 | 14.50% | 10.14% | 4.36% |
| 4/11/1980 | 12.75% | 10.28% | 2.47% |
| 4/14/1980 | 13.85% | 10.29% | 3.56% |
| 4/16/1980 | 15.50% | 10.32% | 5.18% |
| 4/22/1980 | 13.25% | 10.36% | 2.89% |
| 4/22/1980 | 13.90% | 10.36% | 3.54% |
| 4/24/1980 | 16.80% | 10.38% | 6.42% |
| 4/29/1980 | 15.50% | 10.41% | 5.09% |
| 5/6/1980 | 13.70% | 10.45% | 3.25% |
| 5/7/1980 | 15.00% | 10.46% | 4.54% |
| 5/8/1980 | 13.75% | 10.47% | 3.28% |
| 5/9/1980 | 14.35% | 10.47% | 3.88% |
| 5/13/1980 | 13.60% | 10.49% | 3.11% |
| 5/15/1980 | 13.25% | 10.50% | 2.75% |
| 5/19/1980 | 13.75% | 10.52% | 3.23% |
| 5/27/1980 | 13.62% | 10.55% | 3.07% |
| 5/27/1980 | 14.60% | 10.55% | 4.05% |
| 5/29/1980 | 16.00% | 10.56% | 5.44% |
| 5/30/1980 | 13.80% | 10.57% | 3.23% |
| 6/2/1980 | 15.63% | 10.58% | 5.05% |
| 6/9/1980 | 15.90% | 10.61% | 5.29% |
| 6/10/1980 | 13.78% | 10.61% | 3.17% |
| 6/12/1980 | 14.25% | 10.62% | 3.63% |
| 6/19/1980 | 13.40% | 10.63% | 2.77% |
| 6/30/1980 | 13.00% | 10.65% | 2.35% |
| 6/30/1980 | 13.40% | 10.65% | 2.75% |
| 7/9/1980 | 14.75% | 10.68% | 4.07% |
| 7/10/1980 | 15.00% | 10.69% | 4.31% |
| 7/15/1980 | 15.80% | 10.70% | 5.10% |
| 7/18/1980 | 13.80% | 10.72% | 3.08% |
| 7/22/1980 | 14.10% | 10.73% | 3.37% |
| 7/24/1980 | 15.00% | 10.73% | 4.27% |
| 7/25/1980 | 13.48% | 10.74% | 2.74% |
| 7/31/1980 | 14.58% | 10.76% | 3.82% |
| 8/8/1980 | 13.50% | 10.78% | 2.72% |
| 8/8/1980 | 14.00% | 10.78% | 3.22% |
| 8/8/1980 | 15.45% | 10.78% | 4.67% |
| 8/11/1980 | 14.85% | 10.78% | 4.07% |
| 8/14/1980 | 14.00% | 10.79% | 3.21% |
| 8/14/1980 | 16.25% | 10.79% | 5.46% |
| 8/25/1980 | 13.75% | 10.82% | 2.93% |
| 8/27/1980 | 13.80% | 10.83% | 2.97% |
| 8/29/1980 | 12.50% | 10.84% | 1.66% |
| 9/15/1980 | 13.50% | 10.88% | 2.62% |
| 9/15/1980 | 13.93% | 10.88% | 3.05% |
| 9/15/1980 | 15.80% | 10.88% | 4.92% |
| 9/24/1980 | 12.50% | 10.93% | 1.57% |
| 9/24/1980 | 15.00% | 10.93% | 4.07% |
| 9/26/1980 | 13.75% | 10.95% | 2.80% |
| 9/30/1980 | 14.10% | 10.96% | 3.14% |
| 9/30/1980 | 14.20% | 10.96% | 3.24% |
| 10/1/1980 | 13.90% | 10.97% | 2.93% |
| 10/3/1980 | 15.50% | 10.99% | 4.51% |
| 10/7/1980 | 12.50% | 11.00% | 1.50% |
| 10/9/1980 | 13.25% | 11.01% | 2.24% |
| 10/9/1980 | 14.50% | 11.01% | 3.49% |
| 10/9/1980 | 14.50% | 11.01% | 3.49% |
| 10/16/1980 | 16.10% | 11.03% | 5.07% |
| 10/17/1980 | 14.50% | 11.03% | 3.47% |
| 10/31/1980 | 13.75% | 11.11% | 2.64% |
| 10/31/1980 | 14.25% | 11.11% | 3.14% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 11/4/1980 | 15.00% | 11.12% | 3.88% |
| 11/5/1980 | 13.75% | 11.13% | 2.62% |
| 11/5/1980 | 14.00% | 11.13% | 2.87% |
| 11/8/1980 | 13.75% | 11.15% | 2.60% |
| 11/10/1980 | 14.85% | 11.15% | 3.70% |
| 11/17/1980 | 14.00% | 11.18% | 2.82% |
| 11/18/1980 | 14.00% | 11.19% | 2.81% |
| 11/19/1980 | 13.00% | 11.19% | 1.81% |
| 11/24/1980 | 14.00% | 11.20% | 2.80% |
| 11/26/1980 | 14.00% | 11.21% | 2.79% |
| 12/8/1980 | 14.15% | 11.22% | 2.93% |
| 12/8/1980 | 15.10% | 11.22% | 3.88% |
| 12/9/1980 | 15.35% | 11.22% | 4.13% |
| 12/12/1980 | 15.45% | 11.22% | 4.23% |
| 12/17/1980 | 13.25% | 11.23% | 2.02% |
| 12/18/1980 | 15.80% | 11.23% | 4.57% |
| 12/19/1980 | 14.50% | 11.23% | 3.27% |
| 12/19/1980 | 14.64% | 11.23% | 3.41% |
| 12/22/1980 | 13.45% | 11.22% | 2.23% |
| 12/22/1980 | 15.00% | 11.22% | 3.78% |
| 12/30/1980 | 14.50% | 11.21% | 3.29% |
| 12/30/1980 | 14.95% | 11.21% | 3.74% |
| 12/31/1980 | 13.39% | 11.21% | 2.18% |
| 1/2/1981 | 15.25% | 11.21% | 4.04% |
| 1/7/1981 | 14.30% | 11.21% | 3.09% |
| 1/19/1981 | 15.25% | 11.19% | 4.06% |
| 1/23/1981 | 13.10% | 11.20% | 1.90% |
| 1/23/1981 | 14.40% | 11.20% | 3.20% |
| 1/26/1981 | 15.25% | 11.20% | 4.05% |
| 1/27/1981 | 15.00% | 11.20% | 3.80% |
| 1/31/1981 | 13.47% | 11.21% | 2.26% |
| 2/3/1981 | 15.25% | 11.23% | 4.02% |
| 2/5/1981 | 15.75% | 11.25% | 4.50% |
| 2/11/1981 | 15.60% | 11.28% | 4.32% |
| 2/20/1981 | 15.25% | 11.34% | 3.91% |
| 3/11/1981 | 15.40% | 11.50% | 3.90% |
| 3/12/1981 | 14.51% | 11.51% | 3.00% |
| 3/12/1981 | 16.00% | 11.51% | 4.49% |
| 3/13/1981 | 13.02% | 11.52% | 1.50% |
| 3/18/1981 | 16.19% | 11.55% | 4.64% |
| 3/19/1981 | 13.75% | 11.56% | 2.19% |
| 3/23/1981 | 14.30% | 11.58% | 2.72% |
| 3/25/1981 | 15.30% | 11.61% | 3.69% |
| 4/1/1981 | 14.53% | 11.69% | 2.84% |
| 4/3/1981 | 19.10% | 11.72% | 7.38% |
| 4/9/1981 | 15.00% | 11.79% | 3.21% |
| 4/9/1981 | 15.30% | 11.79% | 3.51% |
| 4/9/1981 | 16.50% | 11.79% | 4.71% |
| 4/9/1981 | 17.00% | 11.79% | 5.21% |
| 4/10/1981 | 13.75% | 11.81% | 1.94% |
| 4/13/1981 | 13.57% | 11.83% | 1.74% |
| 4/15/1981 | 15.30% | 11.86% | 3.44% |
| 4/16/1981 | 13.50% | 11.88% | 1.62% |
| 4/17/1981 | 14.10% | 11.88% | 2.22% |
| 4/21/1981 | 14.00% | 11.91% | 2.09% |
| 4/21/1981 | 16.80% | 11.91% | 4.89% |
| 4/24/1981 | 16.00% | 11.96% | 4.04% |
| 4/27/1981 | 12.50% | 11.98% | 0.52% |
| 4/27/1981 | 13.61% | 11.98% | 1.63% |
| 4/29/1981 | 13.65% | 12.01% | 1.64% |
| 4/30/1981 | 13.50% | 12.02% | 1.48% |
| 5/4/1981 | 16.22% | 12.06% | 4.16% |
| 5/5/1981 | 14.40% | 12.08% | 2.32% |
| 5/7/1981 | 16.25% | 12.12% | 4.13% |
| 5/7/1981 | 16.27% | 12.12% | 4.15% |
| 5/8/1981 | 13.00% | 12.14% | 0.86% |
| 5/8/1981 | 16.00% | 12.14% | 3.86% |
| 5/12/1981 | 13.50% | 12.17% | 1.33% |
| 5/15/1981 | 15.75% | 12.23% | 3.52% |
| 5/18/1981 | 14.88% | 12.24% | 2.64% |
| 5/20/1981 | 16.00% | 12.27% | 3.73% |
| 5/21/1981 | 14.00% | 12.28% | 1.72% |
| 5/26/1981 | 14.90% | 12.31% | 2.59% |
| 5/27/1981 | 15.00% | 12.32% | 2.68% |
| 5/29/1981 | 15.50% | 12.34% | 3.16% |
| 6/1/1981 | 16.50% | 12.35% | 4.15% |
| 6/3/1981 | 14.67% | 12.38% | 2.29% |
| 6/5/1981 | 13.00% | 12.40% | 0.60% |
| 6/10/1981 | 16.75% | 12.42% | 4.33% |
| 6/17/1981 | 14.40% | 12.46% | 1.94% |
| 6/18/1981 | 16.33% | 12.47% | 3.86% |
| 6/25/1981 | 14.75% | 12.52% | 2.23% |
| 6/26/1981 | 16.00% | 12.53% | 3.47% |
| 6/30/1981 | 15.25% | 12.55% | 2.70% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 7/1/1981 | 15.50% | 12.56% | 2.94% |
| 7/1/1981 | 17.50% | 12.56% | 4.94% |
| 7/10/1981 | 16.00% | 12.62% | 3.38% |
| 7/14/1981 | 16.90% | 12.64% | 4.26% |
| 7/15/1981 | 16.00% | 12.65% | 3.35% |
| 7/17/1981 | 15.00% | 12.67% | 2.33% |
| 7/20/1981 | 15.00% | 12.68% | 2.32% |
| 7/21/1981 | 14.00% | 12.69% | 1.31% |
| 7/28/1981 | 13.48% | 12.75% | 0.73% |
| 7/31/1981 | 13.50% | 12.79% | 0.71% |
| 7/31/1981 | 15.00% | 12.79% | 2.21% |
| 7/31/1981 | 16.00% | 12.79% | 3.21% |
| 8/5/1981 | 15.71% | 12.83% | 2.88% |
| 8/10/1981 | 14.50% | 12.87% | 1.63% |
| 8/11/1981 | 15.00% | 12.88% | 2.12% |
| 8/20/1981 | 13.50% | 12.95% | 0.55% |
| 8/20/1981 | 16.50% | 12.95% | 3.55% |
| 8/24/1981 | 15.00% | 12.97% | 2.03% |
| 8/28/1981 | 15.00% | 13.01% | 1.99% |
| 9/3/1981 | 14.50% | 13.06% | 1.44% |
| 9/10/1981 | 14.50% | 13.11% | 1.39% |
| 9/11/1981 | 16.00% | 13.12% | 2.88% |
| 9/16/1981 | 16.00% | 13.15% | 2.85% |
| 9/17/1981 | 16.50% | 13.16% | 3.34% |
| 9/23/1981 | 15.85% | 13.20% | 2.65% |
| 9/28/1981 | 15.50% | 13.23% | 2.27% |
| 10/9/1981 | 15.75% | 13.34% | 2.41% |
| 10/15/1981 | 16.25% | 13.37% | 2.88% |
| 10/16/1981 | 15.50% | 13.39% | 2.11% |
| 10/16/1981 | 16.50% | 13.39% | 3.11% |
| 10/19/1981 | 14.25% | 13.40% | 0.85% |
| 10/20/1981 | 15.25% | 13.41% | 1.84% |
| 10/20/1981 | 17.00% | 13.41% | 3.59% |
| 10/23/1981 | 16.00% | 13.46% | 2.54% |
| 10/27/1981 | 10.00% | 13.49% | -3.49% |
| 10/29/1981 | 14.75% | 13.52% | 1.23% |
| 10/29/1981 | 16.50% | 13.52% | 2.98% |
| 11/3/1981 | 15.17% | 13.54% | 1.63% |
| 11/5/1981 | 16.60% | 13.56% | 3.04% |
| 11/6/1981 | 15.17% | 13.57% | 1.60% |
| 11/24/1981 | 15.50% | 13.61% | 1.89% |
| 11/25/1981 | 15.25% | 13.61% | 1.64% |
| 11/25/1981 | 15.35% | 13.61% | 1.74% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 11/25/1981 | 16.10% | 13.61% | 2.49% |
| 12/1/1981 | 15.70% | 13.61% | 2.09% |
| 12/1/1981 | 16.00% | 13.61% | 2.39% |
| 12/1/1981 | 16.49% | 13.61% | 2.88% |
| 12/1/1981 | 16.50% | 13.61% | 2.89% |
| 12/4/1981 | 16.00% | 13.61% | 2.39% |
| 12/11/1981 | 16.25% | 13.63% | 2.62% |
| 12/14/1981 | 14.00% | 13.63% | 0.37% |
| 12/15/1981 | 15.81% | 13.63% | 2.18% |
| 12/15/1981 | 16.00% | 13.63% | 2.37% |
| 12/16/1981 | 15.25% | 13.63% | 1.62% |
| 12/17/1981 | 16.50% | 13.64% | 2.86% |
| 12/18/1981 | 15.45% | 13.64% | 1.81% |
| 12/30/1981 | 14.25% | 13.67% | 0.58% |
| 12/30/1981 | 16.00% | 13.67% | 2.33% |
| 12/30/1981 | 16.25% | 13.67% | 2.58% |
| 12/31/1981 | 16.15% | 13.68% | 2.47% |
| 1/4/1982 | 15.50% | 13.68% | 1.82% |
| 1/11/1982 | 14.50% | 13.73% | 0.77% |
| 1/11/1982 | 17.00% | 13.73% | 3.27% |
| 1/13/1982 | 14.75% | 13.74% | 1.01% |
| 1/14/1982 | 15.75% | 13.75% | 2.00% |
| 1/15/1982 | 15.00% | 13.76% | 1.24% |
| 1/15/1982 | 16.50% | 13.76% | 2.74% |
| 1/22/1982 | 16.25% | 13.80% | 2.45% |
| 1/27/1982 | 16.84% | 13.81% | 3.03% |
| 1/28/1982 | 13.00% | 13.82% | -0.82% |
| 1/29/1982 | 15.50% | 13.82% | 1.68% |
| 2/1/1982 | 15.85% | 13.83% | 2.02% |
| 2/3/1982 | 16.44% | 13.84% | 2.60% |
| 2/8/1982 | 15.50% | 13.86% | 1.64% |
| 2/11/1982 | 16.00% | 13.88% | 2.12% |
| 2/11/1982 | 16.20% | 13.88% | 2.32% |
| 2/17/1982 | 15.00% | 13.89% | 1.11% |
| 2/19/1982 | 15.17% | 13.89% | 1.28% |
| 2/26/1982 | 15.25% | 13.89% | 1.36% |
| 3/1/1982 | 15.03% | 13.89% | 1.14% |
| 3/1/1982 | 16.00% | 13.89% | 2.11% |
| 3/3/1982 | 15.00% | 13.88% | 1.12% |
| 3/8/1982 | 17.10% | 13.88% | 3.22% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/12/1982 | 16.25% | 13.88% | 2.37% |
| 3/17/1982 | 17.30% | 13.88% | 3.42% |
| 3/22/1982 | 15.10% | 13.89% | 1.21% |
| 3/27/1982 | 15.40% | 13.90% | 1.50% |
| 3/30/1982 | 15.50% | 13.91% | 1.59% |
| 3/31/1982 | 17.00% | 13.91% | 3.09% |
| 4/1/1982 | 14.70% | 13.92% | 0.78% |
| 4/1/1982 | 16.50% | 13.92% | 2.58% |
| 4/2/1982 | 15.50% | 13.92% | 1.58% |
| 4/5/1982 | 15.50% | 13.93% | 1.57% |
| 4/8/1982 | 16.40% | 13.94% | 2.46% |
| 4/13/1982 | 14.50% | 13.94% | 0.56% |
| 4/23/1982 | 15.75% | 13.94% | 1.81% |
| 4/27/1982 | 15.00% | 13.94% | 1.06% |
| 4/28/1982 | 15.75% | 13.94% | 1.81% |
| 4/30/1982 | 14.70% | 13.94% | 0.76% |
| 4/30/1982 | 15.50% | 13.94% | 1.56% |
| 5/3/1982 | 16.60% | 13.94% | 2.66% |
| 5/4/1982 | 16.00% | 13.94% | 2.06% |
| 5/14/1982 | 15.50% | 13.92% | 1.58% |
| 5/18/1982 | 15.42% | 13.92% | 1.50% |
| 5/19/1982 | 14.69% | 13.92% | 0.77% |
| 5/20/1982 | 15.00% | 13.91% | 1.09% |
| 5/20/1982 | 15.10% | 13.91% | 1.19% |
| 5/20/1982 | 15.50% | 13.91% | 1.59% |
| 5/20/1982 | 16.30% | 13.91% | 2.39% |
| 5/21/1982 | 17.75% | 13.91% | 3.84% |
| 5/27/1982 | 15.00% | 13.89% | 1.11% |
| 5/28/1982 | 15.50% | 13.89% | 1.61% |
| 5/28/1982 | 17.00% | 13.89% | 3.11% |
| 6/1/1982 | 13.75% | 13.89% | -0.14% |
| 6/1/1982 | 16.60% | 13.89% | 2.71% |
| 6/9/1982 | 17.86% | 13.88% | 3.98% |
| 6/14/1982 | 15.75% | 13.88% | 1.87% |
| 6/15/1982 | 14.85% | 13.87% | 0.98% |
| 6/18/1982 | 15.50% | 13.86% | 1.64% |
| 6/21/1982 | 14.90% | 13.86% | 1.04% |
| 6/23/1982 | 16.00% | 13.86% | 2.14% |
| 6/23/1982 | 16.17% | 13.86% | 2.31% |
| 6/24/1982 | 14.85% | 13.86% | 0.99% |
| 6/25/1982 | 14.70% | 13.85% | 0.85% |
| 7/1/1982 | 16.00% | 13.84% | 2.16% |
| 7/2/1982 | 15.62% | 13.83% | 1.79% |
| 7/2/1982 | 17.00% | 13.83% | 3.17% |
| 7/13/1982 | 14.00% | 13.82% | 0.18% |
| 7/13/1982 | 16.80% | 13.82% | 2.98% |
| 7/14/1982 | 15.76% | 13.81% | 1.95% |
| 7/14/1982 | 16.02% | 13.81% | 2.21% |
| 7/19/1982 | 16.50% | 13.79% | 2.71% |
| 7/22/1982 | 14.50% | 13.76% | 0.74% |
| 7/22/1982 | 17.00% | 13.76% | 3.24% |
| 7/27/1982 | 16.75% | 13.74% | 3.01% |
| 7/29/1982 | 16.50% | 13.73% | 2.77% |
| 8/11/1982 | 17.50% | 13.68% | 3.82% |
| 8/18/1982 | 17.07% | 13.62% | 3.45% |
| 8/20/1982 | 15.73% | 13.60% | 2.13% |
| 8/25/1982 | 16.00% | 13.57% | 2.43% |
| 8/26/1982 | 15.50% | 13.56% | 1.94% |
| 8/30/1982 | 15.00% | 13.55% | 1.45% |
| 9/3/1982 | 16.20% | 13.53% | 2.67% |
| 9/8/1982 | 15.00% | 13.52% | 1.48% |
| 9/15/1982 | 13.08% | 13.51% | -0.43% |
| 9/15/1982 | 16.25% | 13.51% | 2.74% |
| 9/16/1982 | 16.00% | 13.50% | 2.50% |
| 9/17/1982 | 15.25% | 13.50% | 1.75% |
| 9/23/1982 | 17.17% | 13.47% | 3.70% |
| 9/24/1982 | 14.50% | 13.47% | 1.03% |
| 9/27/1982 | 15.25% | 13.46% | 1.79% |
| 10/1/1982 | 15.50% | 13.42% | 2.08% |
| 10/15/1982 | 15.90% | 13.32% | 2.58% |
| 10/22/1982 | 15.75% | 13.24% | 2.51% |
| 10/22/1982 | 17.15% | 13.24% | 3.91% |
| 10/29/1982 | 15.54% | 13.16% | 2.38% |
| 11/1/1982 | 15.50% | 13.14% | 2.36% |
| 11/3/1982 | 17.20% | 13.12% | 4.08% |
| 11/4/1982 | 16.25% | 13.10% | 3.15% |
| 11/5/1982 | 16.20% | 13.09% | 3.11% |
| 11/9/1982 | 16.00% | 13.05% | 2.95% |
| 11/23/1982 | 15.50% | 12.88% | 2.62% |
| 11/23/1982 | 15.85% | 12.88% | 2.97% |
| 11/30/1982 | 16.50% | 12.80% | 3.70% |
| 12/1/1982 | 17.04% | 12.78% | 4.26% |
| 12/6/1982 | 15.00% | 12.72% | 2.28% |
| 12/6/1982 | 16.35% | 12.72% | 3.63% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/10/1982 | 15.50% | 12.66% | 2.84% |
| 12/13/1982 | 16.00% | 12.64% | 3.36% |
| 12/14/1982 | 15.30% | 12.62% | 2.68% |
| 12/14/1982 | 16.40% | 12.62% | 3.78% |
| 12/20/1982 | 16.00% | 12.57% | 3.43% |
| 12/21/1982 | 14.75% | 12.55% | 2.20% |
| 12/21/1982 | 15.85% | 12.55% | 3.30% |
| 12/22/1982 | 16.25% | 12.54% | 3.71% |
| 12/22/1982 | 16.58% | 12.54% | 4.04% |
| 12/22/1982 | 16.75% | 12.54% | 4.21% |
| 12/29/1982 | 14.90% | 12.48% | 2.42% |
| 12/29/1982 | 16.25% | 12.48% | 3.77% |
| 12/30/1982 | 16.00% | 12.46% | 3.54% |
| 12/30/1982 | 16.35% | 12.46% | 3.89% |
| 12/30/1982 | 16.77% | 12.46% | 4.31% |
| 1/5/1983 | 17.33% | 12.40% | 4.93% |
| 1/11/1983 | 15.90% | 12.34% | 3.56% |
| 1/12/1983 | 14.63% | 12.32% | 2.31% |
| 1/12/1983 | 15.50% | 12.32% | 3.18% |
| 1/20/1983 | 17.75% | 12.23% | 5.52% |
| 1/21/1983 | 15.00% | 12.21% | 2.79% |
| 1/24/1983 | 14.50% | 12.20% | 2.30% |
| 1/24/1983 | 15.50% | 12.20% | 3.30% |
| 1/25/1983 | 15.85% | 12.19% | 3.66% |
| 1/27/1983 | 16.14% | 12.16% | 3.98% |
| 2/1/1983 | 18.50% | 12.13% | 6.37% |
| 2/4/1983 | 14.00% | 12.09% | 1.91% |
| 2/10/1983 | 15.00% | 12.05% | 2.95% |
| 2/21/1983 | 15.50% | 11.98% | 3.52% |
| 2/22/1983 | 15.50% | 11.96% | 3.54% |
| 2/23/1983 | 15.10% | 11.95% | 3.15% |
| 2/23/1983 | 16.00% | 11.95% | 4.05% |
| 3/2/1983 | 15.25% | 11.89% | 3.36% |
| 3/9/1983 | 15.20% | 11.82% | 3.38% |
| 3/15/1983 | 13.00% | 11.76% | 1.24% |
| 3/18/1983 | 15.25% | 11.72% | 3.53% |
| 3/23/1983 | 15.40% | 11.68% | 3.72% |
| 3/24/1983 | 15.00% | 11.66% | 3.34% |
| 3/29/1983 | 15.50% | 11.62% | 3.88% |
| 3/30/1983 | 16.71% | 11.60% | 5.11% |
| 3/31/1983 | 15.00% | 11.58% | 3.42% |
| 4/4/1983 | 15.20% | 11.57% | 3.63% |
| 4/8/1983 | 15.50% | 11.49% | 4.01% |
| 4/11/1983 | 14.81% | 11.48% | 3.33% |
| 4/19/1983 | 14.50% | 11.36% | 3.14% |
| 4/20/1983 | 16.00% | 11.35% | 4.65% |
| 4/29/1983 | 16.00% | 11.23% | 4.77% |
| 5/1/1983 | 14.50% | 11.23% | 3.27% |
| 5/9/1983 | 15.50% | 11.14% | 4.36% |
| 5/11/1983 | 16.46% | 11.11% | 5.35% |
| 5/12/1983 | 14.14% | 11.10% | 3.04% |
| 5/18/1983 | 15.00% | 11.04% | 3.96% |
| 5/23/1983 | 14.90% | 11.00% | 3.90% |
| 5/23/1983 | 15.50% | 11.00% | 4.50% |
| 5/25/1983 | 15.50% | 10.97% | 4.53% |
| 5/27/1983 | 15.00% | 10.95% | 4.05% |
| 5/31/1983 | 14.00% | 10.94% | 3.06% |
| 5/31/1983 | 15.50% | 10.94% | 4.56% |
| 6/2/1983 | 14.50% | 10.92% | 3.58% |
| 6/17/1983 | 15.03% | 10.83% | 4.20% |
| 7/1/1983 | 14.80% | 10.77% | 4.03% |
| 7/1/1983 | 14.90% | 10.77% | 4.13% |
| 7/8/1983 | 16.25% | 10.75% | 5.50% |
| 7/13/1983 | 13.20% | 10.75% | 2.45% |
| 7/19/1983 | 15.00% | 10.74% | 4.26% |
| 7/19/1983 | 15.10% | 10.74% | 4.36% |
| 7/25/1983 | 16.25% | 10.73% | 5.52% |
| 7/28/1983 | 15.90% | 10.74% | 5.16% |
| 8/3/1983 | 16.34% | 10.75% | 5.59% |
| 8/3/1983 | 16.50% | 10.75% | 5.75% |
| 8/19/1983 | 15.00% | 10.80% | 4.20% |
| 8/22/1983 | 15.50% | 10.80% | 4.70% |
| 8/22/1983 | 16.40% | 10.80% | 5.60% |
| 8/31/1983 | 14.75% | 10.85% | 3.90% |
| 9/7/1983 | 15.00% | 10.87% | 4.13% |
| 9/14/1983 | 15.78% | 10.89% | 4.89% |
| 9/16/1983 | 15.00% | 10.90% | 4.10% |
| 9/19/1983 | 14.50% | 10.91% | 3.59% |
| 9/20/1983 | 16.50% | 10.91% | 5.59% |
| 9/28/1983 | 14.50% | 10.94% | 3.56% |
| 9/29/1983 | 15.50% | 10.95% | 4.55% |
| 9/30/1983 | 15.25% | 10.95% | 4.30% |
| 9/30/1983 | 16.15% | 10.95% | 5.20% |
| 10/4/1983 | 14.80% | 10.96% | 3.84% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/7/1983 | 16.00% | 10.97% | 5.03% |
| 10/13/1983 | 15.52% | 10.99% | 4.53% |
| 10/17/1983 | 15.50% | 11.00% | 4.50% |
| 10/18/1983 | 14.50% | 11.00% | 3.50% |
| 10/19/1983 | 16.25% | 11.01% | 5.24% |
| 10/19/1983 | 16.50% | 11.01% | 5.49% |
| 10/26/1983 | 15.00% | 11.04% | 3.96% |
| 10/27/1983 | 15.20% | 11.04% | 4.16% |
| 11/1/1983 | 16.00% | 11.06% | 4.94% |
| 11/9/1983 | 14.90% | 11.09% | 3.81% |
| 11/10/1983 | 14.35% | 11.10% | 3.25% |
| 11/23/1983 | 16.00% | 11.13% | 4.87% |
| 11/23/1983 | 16.15% | 11.13% | 5.02% |
| 11/30/1983 | 15.00% | 11.14% | 3.86% |
| 12/5/1983 | 15.25% | 11.15% | 4.10% |
| 12/6/1983 | 15.07% | 11.16% | 3.91% |
| 12/8/1983 | 15.90% | 11.16% | 4.74% |
| 12/9/1983 | 14.75% | 11.17% | 3.58% |
| 12/12/1983 | 14.50% | 11.18% | 3.32% |
| 12/15/1983 | 15.56% | 11.20% | 4.36% |
| 12/19/1983 | 14.80% | 11.21% | 3.59% |
| 12/20/1983 | 14.69% | 11.22% | 3.47% |
| 12/20/1983 | 16.00% | 11.22% | 4.78% |
| 12/20/1983 | 16.25% | 11.22% | 5.03% |
| 12/22/1983 | 14.75% | 11.23% | 3.52% |
| 12/22/1983 | 15.75% | 11.23% | 4.52% |
| 1/3/1984 | 14.75% | 11.27% | 3.48% |
| 1/10/1984 | 15.90% | 11.30% | 4.60% |
| 1/12/1984 | 15.60% | 11.31% | 4.29% |
| 1/18/1984 | 13.75% | 11.33% | 2.42% |
| 1/19/1984 | 15.90% | 11.33% | 4.57% |
| 1/30/1984 | 16.10% | 11.37% | 4.73% |
| 1/31/1984 | 15.25% | 11.38% | 3.87% |
| 2/1/1984 | 14.80% | 11.39% | 3.41% |
| 2/6/1984 | 13.75% | 11.41% | 2.34% |
| 2/6/1984 | 14.75% | 11.41% | 3.34% |
| 2/9/1984 | 15.25% | 11.43% | 3.82% |
| 2/15/1984 | 15.70% | 11.45% | 4.25% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/20/1984 | 15.00% | 11.46% | 3.54% |
| 2/22/1984 | 14.75% | 11.48% | 3.27% |
| 2/28/1984 | 14.50% | 11.52% | 2.98% |
| 3/2/1984 | 14.25% | 11.54% | 2.71% |
| 3/20/1984 | 16.00% | 11.65% | 4.35% |
| 3/23/1984 | 15.50% | 11.67% | 3.83% |
| 3/26/1984 | 14.71% | 11.68% | 3.03% |
| 4/2/1984 | 15.50% | 11.72% | 3.78% |
| 4/6/1984 | 14.74% | 11.76% | 2.98% |
| 4/11/1984 | 15.72% | 11.78% | 3.94% |
| 4/17/1984 | 15.00% | 11.81% | 3.19% |
| 4/18/1984 | 16.20% | 11.82% | 4.38% |
| 4/25/1984 | 14.64% | 11.85% | 2.79% |
| 4/30/1984 | 14.40% | 11.88% | 2.52% |
| 5/16/1984 | 14.69% | 11.99% | 2.70% |
| 5/16/1984 | 15.00% | 11.99% | 3.01% |
| 5/22/1984 | 14.40% | 12.02% | 2.38% |
| 5/29/1984 | 15.10% | 12.06% | 3.04% |
| 6/13/1984 | 15.25% | 12.16% | 3.09% |
| 6/15/1984 | 15.60% | 12.17% | 3.43% |
| 6/22/1984 | 16.25% | 12.21% | 4.04% |
| 6/29/1984 | 15.25% | 12.26% | 2.99% |
| 7/2/1984 | 13.35% | 12.27% | 1.08% |
| 7/10/1984 | 16.00% | 12.31% | 3.69% |
| 7/12/1984 | 16.50% | 12.33% | 4.17% |
| 7/13/1984 | 16.25% | 12.34% | 3.91% |
| 7/17/1984 | 14.14% | 12.35% | 1.79% |
| 7/18/1984 | 15.30% | 12.36% | 2.94% |
| 7/18/1984 | 15.50% | 12.36% | 3.14% |
| 7/19/1984 | 14.30% | 12.37% | 1.93% |
| 7/24/1984 | 16.79% | 12.40% | 4.39% |
| 7/31/1984 | 16.00% | 12.43% | 3.57% |
| 8/3/1984 | 14.25% | 12.45% | 1.80% |
| 8/17/1984 | 14.30% | 12.49% | 1.81% |
| 8/20/1984 | 15.00% | 12.49% | 2.51% |
| 8/27/1984 | 16.30% | 12.51% | 3.79% |
| 8/31/1984 | 15.55% | 12.53% | 3.02% |
| 9/6/1984 | 16.00% | 12.54% | 3.46% |
| 9/10/1984 | 14.75% | 12.55% | 2.20% |
| 9/13/1984 | 15.00% | 12.55% | 2.45% |
| 9/17/1984 | 17.38% | 12.56% | 4.82% |
| 9/26/1984 | 14.50% | 12.57% | 1.93% |
| 9/28/1984 | 15.00% | 12.57% | 2.43% |
| 9/28/1984 | 16.25% | 12.57% | 3.68% |
| 10/9/1984 | 14.75% | 12.58% | 2.17% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/12/1984 | 15.60% | 12.59% | 3.01% |
| 10/22/1984 | 15.00% | 12.59% | 2.41% |
| 10/26/1984 | 16.40% | 12.59% | 3.81% |
| 10/31/1984 | 16.25% | 12.59% | 3.66% |
| 11/7/1984 | 15.60% | 12.58% | 3.02% |
| 11/9/1984 | 16.00% | 12.58% | 3.42% |
| 11/14/1984 | 15.75% | 12.59% | 3.16% |
| 11/20/1984 | 15.25% | 12.58% | 2.67% |
| 11/20/1984 | 15.92% | 12.58% | 3.34% |
| 11/23/1984 | 15.00% | 12.58% | 2.42% |
| 11/28/1984 | 16.15% | 12.57% | 3.58% |
| 12/3/1984 | 15.80% | 12.57% | 3.23% |
| 12/4/1984 | 16.50% | 12.56% | 3.94% |
| 12/18/1984 | 16.40% | 12.54% | 3.86% |
| 12/19/1984 | 14.75% | 12.53% | 2.22% |
| 12/19/1984 | 15.00% | 12.53% | 2.47% |
| 12/20/1984 | 16.00% | 12.53% | 3.47% |
| 12/28/1984 | 16.00% | 12.50% | 3.50% |
| 1/3/1985 | 14.75% | 12.49% | 2.26% |
| 1/10/1985 | 15.75% | 12.47% | 3.28% |
| 1/11/1985 | 16.30% | 12.46% | 3.84% |
| 1/23/1985 | 15.80% | 12.43% | 3.37% |
| 1/24/1985 | 15.82% | 12.43% | 3.39% |
| 1/25/1985 | 16.75% | 12.42% | 4.33% |
| 1/30/1985 | 14.90% | 12.40% | 2.50% |
| 1/31/1985 | 14.75% | 12.39% | 2.36% |
| 2/8/1985 | 14.47% | 12.35% | 2.12% |
| 3/1/1985 | 13.84% | 12.30% | 1.54% |
| 3/8/1985 | 16.85% | 12.28% | 4.57% |
| 3/14/1985 | 15.50% | 12.25% | 3.25% |
| 3/15/1985 | 15.62% | 12.25% | 3.37% |
| 3/29/1985 | 15.62% | 12.16% | 3.46% |
| 4/3/1985 | 14.60% | 12.13% | 2.47% |
| 4/9/1985 | 15.50% | 12.10% | 3.40% |
| 4/16/1985 | 15.70% | 12.05% | 3.65% |
| 4/22/1985 | 14.00% | 12.01% | 1.99% |
| 4/26/1985 | 15.50% | 11.97% | 3.53% |
| 4/29/1985 | 15.00% | 11.96% | 3.04% |
| 5/2/1985 | 14.68% | 11.93% | 2.75% |
| 5/8/1985 | 15.62% | 11.88% | 3.74% |
| 5/10/1985 | 16.50% | 11.86% | 4.64% |
| 5/29/1985 | 14.61% | 11.73% | 2.88% |
| 5/31/1985 | 16.00% | 11.71% | 4.29% |
| 6/14/1985 | 15.50% | 11.60% | 3.90% |
| 7/9/1985 | 15.00% | 11.44% | 3.56% |
| 7/16/1985 | 14.50% | 11.39% | 3.11% |
| 7/26/1985 | 14.50% | 11.32% | 3.18% |
| 8/2/1985 | 14.80% | 11.29% | 3.51% |
| 8/7/1985 | 15.00% | 11.26% | 3.74% |
| 8/28/1985 | 14.25% | 11.15% | 3.10% |
| 8/28/1985 | 15.50% | 11.15% | 4.35% |
| 8/29/1985 | 14.50% | 11.14% | 3.36% |
| 9/9/1985 | 14.60% | 11.11% | 3.49% |
| 9/9/1985 | 14.90% | 11.11% | 3.79% |
| 9/17/1985 | 14.90% | 11.08% | 3.82% |
| 9/23/1985 | 15.00% | 11.06% | 3.94% |
| 9/27/1985 | 15.50% | 11.04% | 4.46% |
| 9/27/1985 | 15.80% | 11.04% | 4.76% |
| 10/2/1985 | 14.00% | 11.03% | 2.97% |
| 10/2/1985 | 14.75% | 11.03% | 3.72% |
| 10/3/1985 | 15.25% | 11.03% | 4.22% |
| 10/24/1985 | 15.40% | 10.96% | 4.44% |
| 10/24/1985 | 15.82% | 10.96% | 4.86% |
| 10/24/1985 | 15.85% | 10.96% | 4.89% |
| 10/28/1985 | 16.00% | 10.95% | 5.05% |
| 10/29/1985 | 16.65% | 10.94% | 5.71% |
| 10/31/1985 | 15.06% | 10.93% | 4.13% |
| 11/4/1985 | 14.50% | 10.91% | 3.59% |
| 11/7/1985 | 15.50% | 10.89% | 4.61% |
| 11/8/1985 | 14.30% | 10.89% | 3.41% |
| 12/12/1985 | 14.75% | 10.73% | 4.02% |
| 12/18/1985 | 15.00% | 10.69% | 4.31% |
| 12/20/1985 | 14.50% | 10.66% | 3.84% |
| 12/20/1985 | 14.50% | 10.66% | 3.84% |
| 12/20/1985 | 15.00% | 10.66% | 4.34% |
| 1/24/1986 | 15.40% | 10.40% | 5.00% |
| 1/31/1986 | 15.00% | 10.35% | 4.65% |
| 2/5/1986 | 15.00% | 10.32% | 4.68% |
| 2/5/1986 | 15.75% | 10.32% | 5.43% |
| 2/10/1986 | 13.30% | 10.29% | 3.01% |
| 2/11/1986 | 12.50% | 10.27% | 2.23% |
| 2/14/1986 | 14.40% | 10.24% | 4.16% |
| 2/18/1986 | 16.00% | 10.22% | 5.78% |
| 2/24/1986 | 14.50% | 10.17% | 4.33% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 2/26/1986 | 14.00% | 10.15% | 3.85% |
| 3/5/1986 | 14.90% | 10.07% | 4.83% |
| 3/11/1986 | 14.50% | 10.01% | 4.49% |
| 3/12/1986 | 13.50% | 10.00% | 3.50% |
| 3/27/1986 | 14.10% | 9.85% | 4.25% |
| 3/31/1986 | 13.50% | 9.84% | 3.66% |
| 4/1/1986 | 14.00% | 9.82% | 4.18% |
| 4/2/1986 | 15.50% | 9.81% | 5.69% |
| 4/4/1986 | 15.00% | 9.78% | 5.22% |
| 4/14/1986 | 13.40% | 9.68% | 3.72% |
| 4/23/1986 | 15.00% | 9.57% | 5.43% |
| 5/16/1986 | 14.50% | 9.31% | 5.19% |
| 5/16/1986 | 14.50% | 9.31% | 5.19% |
| 5/29/1986 | 13.90% | 9.19% | 4.71% |
| 5/30/1986 | 15.10% | 9.17% | 5.93% |
| 6/2/1986 | 12.81% | 9.16% | 3.65% |
| 6/11/1986 | 14.00% | 9.06% | 4.94% |
| 6/24/1986 | 16.63% | 8.93% | 7.70% |
| 6/26/1986 | 12.00% | 8.90% | 3.10% |
| 6/26/1986 | 14.75% | 8.90% | 5.85% |
| 6/30/1986 | 13.00% | 8.86% | 4.14% |
| 7/10/1986 | 14.34% | 8.74% | 5.60% |
| 7/11/1986 | 12.75% | 8.72% | 4.03% |
| 7/14/1986 | 12.60% | 8.71% | 3.89% |
| 7/17/1986 | 12.40% | 8.65% | 3.75% |
| 7/25/1986 | 14.25% | 8.56% | 5.69% |
| 8/6/1986 | 13.50% | 8.43% | 5.07% |
| 8/14/1986 | 13.50% | 8.34% | 5.16% |
| 9/16/1986 | 12.75% | 8.06% | 4.69% |
| 9/19/1986 | 13.25% | 8.02% | 5.23% |
| 10/1/1986 | 14.00% | 7.94% | 6.06% |
| 10/3/1986 | 13.40% | 7.92% | 5.48% |
| 10/31/1986 | 13.50% | 7.77% | 5.73% |
| 11/5/1986 | 13.00% | 7.74% | 5.26% |
| 12/3/1986 | 12.90% | 7.58% | 5.32% |
| 12/4/1986 | 14.44% | 7.57% | 6.87% |
| 12/16/1986 | 13.60% | 7.52% | 6.08% |
| 12/22/1986 | 13.80% | 7.50% | 6.30% |
| 12/30/1986 | 13.00% | 7.49% | 5.51% |
| 1/2/1987 | 13.00% | 7.48% | 5.52% |
| 1/12/1987 | 12.40% | 7.46% | 4.94% |
| 1/27/1987 | 12.71% | 7.46% | 5.25% |
| 3/2/1987 | 12.47% | 7.47% | 5.00% |
| 3/3/1987 | 13.60% | 7.47% | 6.13% |
| 3/4/1987 | 12.38% | 7.47% | 4.91% |
| 3/10/1987 | 13.50% | 7.47% | 6.03% |
| 3/13/1987 | 13.00% | 7.47% | 5.53% |
| 3/31/1987 | 13.00% | 7.46% | 5.54% |
| 4/6/1987 | 13.00% | 7.47% | 5.53% |
| 4/14/1987 | 12.50% | 7.49% | 5.01% |
| 4/16/1987 | 14.50% | 7.50% | 7.00% |
| 4/27/1987 | 12.00% | 7.54% | 4.46% |
| 5/5/1987 | 12.85% | 7.58% | 5.27% |
| 5/12/1987 | 12.65% | 7.62% | 5.03% |
| 5/28/1987 | 13.50% | 7.70% | 5.80% |
| 6/15/1987 | 13.20% | 7.78% | 5.42% |
| 6/29/1987 | 15.00% | 7.84% | 7.16% |
| 6/30/1987 | 12.50% | 7.84% | 4.66% |
| 7/8/1987 | 12.00% | 7.86% | 4.14% |
| 7/10/1987 | 12.90% | 7.87% | 5.03% |
| 7/15/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 13.50% | 7.88% | 5.62% |
| 7/16/1987 | 15.00% | 7.88% | 7.12% |
| 7/27/1987 | 13.00% | 7.92% | 5.08% |
| 7/27/1987 | 13.40% | 7.92% | 5.48% |
| 7/27/1987 | 13.50% | 7.92% | 5.58% |
| 7/31/1987 | 12.98% | 7.95% | 5.03% |
| 8/26/1987 | 12.63% | 8.06% | 4.57% |
| 8/26/1987 | 12.75% | 8.06% | 4.69% |
| 8/27/1987 | 13.25% | 8.07% | 5.18% |
| 9/9/1987 | 13.00% | 8.14% | 4.86% |
| 9/30/1987 | 12.75% | 8.31% | 4.44% |
| 9/30/1987 | 13.00% | 8.31% | 4.69% |
| 10/2/1987 | 11.50% | 8.33% | 3.17% |
| 10/15/1987 | 13.00% | 8.44% | 4.56% |
| 11/2/1987 | 13.00% | 8.55% | 4.45% |
| 11/19/1987 | 13.00% | 8.64% | 4.36% |
| 11/30/1987 | 12.00% | 8.69% | 3.31% |
| 12/3/1987 | 14.20% | 8.71% | 5.49% |
| 12/15/1987 | 13.25% | 8.78% | 4.47% |
| 12/16/1987 | 13.50% | 8.79% | 4.71% |
| 12/16/1987 | 13.72% | 8.79% | 4.93% |
| 12/17/1987 | 11.75% | 8.80% | 2.95% |
| 12/18/1987 | 13.50% | 8.80% | 4.70% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 12/21/1987 | 12.01% | 8.81% | 3.20% |
| 12/22/1987 | 12.00% | 8.82% | 3.18% |
| 12/22/1987 | 12.00% | 8.82% | 3.18% |
| 12/22/1987 | 12.75% | 8.82% | 3.93% |
| 12/22/1987 | 13.00% | 8.82% | 4.18% |
| 1/20/1988 | 13.80% | 8.94% | 4.86% |
| 1/26/1988 | 13.90% | 8.96% | 4.94% |
| 1/29/1988 | 13.20% | 8.96% | 4.24% |
| 2/4/1988 | 12.60% | 8.96% | 3.64% |
| 3/1/1988 | 11.56% | 8.94% | 2.62% |
| 3/23/1988 | 12.87% | 8.92% | 3.95% |
| 3/24/1988 | 11.24% | 8.92% | 2.32% |
| 3/30/1988 | 12.72% | 8.92% | 3.80% |
| 4/1/1988 | 12.50% | 8.92% | 3.58% |
| 4/7/1988 | 13.25% | 8.93% | 4.32% |
| 4/25/1988 | 10.96% | 8.96% | 2.00% |
| 5/3/1988 | 12.91% | 8.98% | 3.93% |
| 5/11/1988 | 13.50% | 8.99% | 4.51% |
| 5/16/1988 | 13.00% | 8.99% | 4.01% |
| 6/30/1988 | 12.75% | 8.99% | 3.76% |
| 7/1/1988 | 12.75% | 8.99% | 3.76% |
| 7/20/1988 | 13.40% | 8.96% | 4.44% |
| 8/5/1988 | 12.75% | 8.91% | 3.84% |
| 8/23/1988 | 11.70% | 8.93% | 2.77% |
| 8/29/1988 | 12.75% | 8.94% | 3.81% |
| 8/30/1988 | 13.50% | 8.94% | 4.56% |
| 9/8/1988 | 12.60% | 8.95% | 3.65% |
| 10/13/1988 | 13.10% | 8.93% | 4.17% |
| 12/19/1988 | 13.00% | 9.02% | 3.98% |
| 12/20/1988 | 12.25% | 9.02% | 3.23% |
| 12/20/1988 | 13.00% | 9.02% | 3.98% |
| 12/21/1988 | 12.90% | 9.02% | 3.88% |
| 12/27/1988 | 13.00% | 9.03% | 3.97% |
| 12/28/1988 | 13.10% | 9.03% | 4.07% |
| 12/30/1988 | 13.40% | 9.04% | 4.36% |
| 1/27/1989 | 13.00% | 9.06% | 3.94% |
| 1/31/1989 | 13.00% | 9.06% | 3.94% |
| 2/17/1989 | 13.00% | 9.05% | 3.95% |
| 2/20/1989 | 12.40% | 9.05% | 3.35% |
| 3/1/1989 | 12.76% | 9.05% | 3.71% |
| 3/8/1989 | 13.00% | 9.05% | 3.95% |
| 3/30/1989 | 14.00% | 9.05% | 4.95% |
| 4/5/1989 | 14.20% | 9.05% | 5.15% |
| 4/18/1989 | 13.00% | 9.05% | 3.95% |
| 5/5/1989 | 12.40% | 9.05% | 3.35% |
| 6/2/1989 | 13.20% | 9.00% | 4.20% |
| 6/8/1989 | 13.50% | 8.98% | 4.52% |
| 6/27/1989 | 13.25% | 8.91% | 4.34% |
| 6/30/1989 | 13.00% | 8.90% | 4.10% |
| 8/14/1989 | 12.50% | 8.77% | 3.73% |
| 9/28/1989 | 12.25% | 8.63% | 3.62% |
| 10/24/1989 | 12.50% | 8.54% | 3.96% |
| 11/9/1989 | 13.00% | 8.48% | 4.52% |
| 12/15/1989 | 13.00% | 8.33% | 4.67% |
| 12/20/1989 | 12.90% | 8.31% | 4.59% |
| 12/21/1989 | 12.90% | 8.31% | 4.59% |
| 12/27/1989 | 12.50% | 8.29% | 4.21% |
| 12/27/1989 | 13.00% | 8.29% | 4.71% |
| 1/10/1990 | 12.80% | 8.24% | 4.56% |
| 1/11/1990 | 12.90% | 8.23% | 4.67% |
| 1/17/1990 | 12.80% | 8.22% | 4.58% |
| 1/26/1990 | 12.00% | 8.19% | 3.81% |
| 2/9/1990 | 12.10% | 8.17% | 3.93% |
| 2/24/1990 | 12.86% | 8.15% | 4.71% |
| 3/30/1990 | 12.90% | 8.16% | 4.74% |
| 4/4/1990 | 15.76% | 8.17% | 7.59% |
| 4/12/1990 | 12.52% | 8.18% | 4.34% |
| 4/19/1990 | 12.75% | 8.20% | 4.55% |
| 5/21/1990 | 12.10% | 8.28% | 3.82% |
| 5/29/1990 | 12.40% | 8.30% | 4.10% |
| 5/31/1990 | 12.00% | 8.30% | 3.70% |
| 6/4/1990 | 12.90% | 8.30% | 4.60% |
| 6/6/1990 | 12.25% | 8.31% | 3.94% |
| 6/15/1990 | 13.20% | 8.32% | 4.88% |
| 6/20/1990 | 12.92% | 8.32% | 4.60% |
| 6/27/1990 | 12.90% | 8.33% | 4.57% |
| 6/29/1990 | 12.50% | 8.34% | 4.16% |
| 7/6/1990 | 12.10% | 8.34% | 3.76% |
| 7/6/1990 | 12.35% | 8.34% | 4.01% |
| 8/10/1990 | 12.55% | 8.41% | 4.14% |
| 8/16/1990 | 13.21% | 8.43% | 4.78% |
| 8/22/1990 | 13.10% | 8.45% | 4.65% |
| 8/24/1990 | 13.00% | 8.46% | 4.54% |
| 9/26/1990 | 11.45% | 8.59% | 2.86% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/2/1990 | 13.00% | 8.61% | 4.39% |
| 10/5/1990 | 12.84% | 8.63% | 4.21% |
| 10/19/1990 | 13.00% | 8.67% | 4.33% |
| 10/25/1990 | 12.30% | 8.68% | 3.62% |
| 11/21/1990 | 12.70% | 8.69% | 4.01% |
| 12/13/1990 | 12.30% | 8.67% | 3.63% |
| 12/17/1990 | 12.87% | 8.67% | 4.20% |
| 12/18/1990 | 13.10% | 8.67% | 4.43% |
| 12/19/1990 | 12.00% | 8.66% | 3.34% |
| 12/20/1990 | 12.75% | 8.66% | 4.09% |
| 12/21/1990 | 12.50% | 8.66% | 3.84% |
| 12/27/1990 | 12.79% | 8.66% | 4.13% |
| 1/2/1991 | 13.10% | 8.66% | 4.44% |
| 1/4/1991 | 12.50% | 8.65% | 3.85% |
| 1/15/1991 | 12.75% | 8.65% | 4.10% |
| 1/25/1991 | 11.70% | 8.63% | 3.07% |
| 2/4/1991 | 12.50% | 8.60% | 3.90% |
| 2/7/1991 | 12.50% | 8.59% | 3.91% |
| 2/12/1991 | 13.00% | 8.57% | 4.43% |
| 2/14/1991 | 12.72% | 8.56% | 4.16% |
| 2/22/1991 | 12.80% | 8.55% | 4.25% |
| 3/6/1991 | 13.10% | 8.53% | 4.57% |
| 3/8/1991 | 12.30% | 8.52% | 3.78% |
| 3/8/1991 | 13.00% | 8.52% | 4.48% |
| 4/22/1991 | 13.00% | 8.49% | 4.51% |
| 5/7/1991 | 13.50% | 8.47% | 5.03% |
| 5/13/1991 | 13.25% | 8.47% | 4.78% |
| 5/30/1991 | 12.75% | 8.43% | 4.32% |
| 6/12/1991 | 12.00% | 8.41% | 3.59% |
| 6/25/1991 | 11.70% | 8.38% | 3.32% |
| 6/28/1991 | 12.50% | 8.38% | 4.12% |
| 7/1/1991 | 12.00% | 8.37% | 3.63% |
| 7/3/1991 | 12.50% | 8.36% | 4.14% |
| 7/19/1991 | 12.10% | 8.34% | 3.76% |
| 8/1/1991 | 12.90% | 8.32% | 4.58% |
| 8/16/1991 | 13.20% | 8.29% | 4.91% |
| 9/27/1991 | 12.50% | 8.23% | 4.27% |
| 9/30/1991 | 12.25% | 8.23% | 4.02% |
| 10/17/1991 | 13.00% | 8.20% | 4.80% |
| 10/23/1991 | 12.50% | 8.20% | 4.30% |
| 10/23/1991 | 12.55% | 8.20% | 4.35% |
| 10/31/1991 | 11.80% | 8.19% | 3.61% |
| 11/1/1991 | 12.00% | 8.19% | 3.81% |
| 11/5/1991 | 12.25% | 8.19% | 4.06% |
| 11/12/1991 | 12.50% | 8.18% | 4.32% |
| 11/12/1991 | 13.25% | 8.18% | 5.07% |
| 11/25/1991 | 12.40% | 8.18% | 4.22% |
| 11/26/1991 | 11.60% | 8.18% | 3.42% |
| 11/26/1991 | 12.50% | 8.18% | 4.32% |
| 11/27/1991 | 12.10% | 8.18% | 3.92% |
| 12/18/1991 | 12.25% | 8.15% | 4.10% |
| 12/19/1991 | 12.60% | 8.15% | 4.45% |
| 12/19/1991 | 12.80% | 8.15% | 4.65% |
| 12/20/1991 | 12.65% | 8.14% | 4.51% |
| 1/9/1992 | 12.80% | 8.09% | 4.71% |
| 1/16/1992 | 12.75% | 8.07% | 4.68% |
| 1/21/1992 | 12.00% | 8.06% | 3.94% |
| 1/22/1992 | 13.00% | 8.06% | 4.94% |
| 1/27/1992 | 12.65% | 8.05% | 4.60% |
| 1/31/1992 | 12.00% | 8.04% | 3.96% |
| 2/11/1992 | 12.40% | 8.03% | 4.37% |
| 2/25/1992 | 12.50% | 8.01% | 4.49% |
| 3/16/1992 | 11.43% | 7.98% | 3.45% |
| 3/18/1992 | 12.28% | 7.98% | 4.30% |
| 4/2/1992 | 12.10% | 7.95% | 4.15% |
| 4/9/1992 | 11.45% | 7.93% | 3.52% |
| 4/10/1992 | 11.50% | 7.93% | 3.57% |
| 4/14/1992 | 11.50% | 7.92% | 3.58% |
| 5/5/1992 | 11.50% | 7.89% | 3.61% |
| 5/12/1992 | 11.87% | 7.88% | 3.99% |
| 5/12/1992 | 12.46% | 7.88% | 4.58% |
| 6/1/1992 | 12.30% | 7.86% | 4.44% |
| 6/12/1992 | 10.90% | 7.85% | 3.05% |
| 6/26/1992 | 12.35% | 7.85% | 4.50% |
| 6/29/1992 | 11.00% | 7.85% | 3.15% |
| 6/30/1992 | 13.00% | 7.85% | 5.15% |
| 7/13/1992 | 11.90% | 7.84% | 4.06% |
| 7/13/1992 | 13.50% | 7.84% | 5.66% |
| 7/22/1992 | 11.20% | 7.83% | 3.37% |
| 8/3/1992 | 12.00% | 7.81% | 4.19% |
| 8/6/1992 | 12.50% | 7.80% | 4.70% |
| 9/22/1992 | 12.00% | 7.71% | 4.29% |
| 9/28/1992 | 11.40% | 7.71% | 3.69% |
| 9/30/1992 | 11.75% | 7.71% | 4.04% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 10/2/1992 | 13.00% | 7.70% | 5.30% |
| 10/12/1992 | 12.20% | 7.70% | 4.50% |
| 10/16/1992 | 13.16% | 7.71% | 5.45% |
| 10/30/1992 | 11.75% | 7.71% | 4.04% |
| 11/3/1992 | 12.00% | 7.71% | 4.29% |
| 12/3/1992 | 11.85% | 7.68% | 4.17% |
| 12/15/1992 | 11.00% | 7.66% | 3.34% |
| 12/16/1992 | 11.90% | 7.66% | 4.24% |
| 12/16/1992 | 12.40% | 7.66% | 4.74% |
| 12/17/1992 | 12.00% | 7.66% | 4.34% |
| 12/22/1992 | 12.30% | 7.65% | 4.65% |
| 12/22/1992 | 12.40% | 7.65% | 4.75% |
| 12/29/1992 | 12.25% | 7.63% | 4.62% |
| 12/30/1992 | 12.00% | 7.63% | 4.37% |
| 12/31/1992 | 11.90% | 7.62% | 4.28% |
| 1/12/1993 | 12.00% | 7.61% | 4.39% |
| 1/21/1993 | 11.25% | 7.59% | 3.66% |
| 2/2/1993 | 11.40% | 7.56% | 3.84% |
| 2/15/1993 | 12.30% | 7.52% | 4.78% |
| 2/24/1993 | 11.90% | 7.49% | 4.41% |
| 2/26/1993 | 11.80% | 7.48% | 4.32% |
| 2/26/1993 | 12.20% | 7.48% | 4.72% |
| 4/23/1993 | 11.75% | 7.29% | 4.46% |
| 5/11/1993 | 11.75% | 7.24% | 4.51% |
| 5/14/1993 | 11.50% | 7.24% | 4.26% |
| 5/25/1993 | 11.50% | 7.22% | 4.28% |
| 5/28/1993 | 11.00% | 7.22% | 3.78% |
| 6/3/1993 | 12.00% | 7.21% | 4.79% |
| 6/16/1993 | 11.50% | 7.19% | 4.31% |
| 6/18/1993 | 12.10% | 7.18% | 4.92% |
| 6/25/1993 | 11.67% | 7.17% | 4.50% |
| 7/21/1993 | 11.38% | 7.10% | 4.28% |
| 7/23/1993 | 10.46% | 7.09% | 3.37% |
| 8/24/1993 | 11.50% | 6.95% | 4.55% |
| 9/21/1993 | 10.50% | 6.80% | 3.70% |
| 9/29/1993 | 11.47% | 6.76% | 4.71% |
| 9/30/1993 | 11.60% | 6.76% | 4.84% |
| 11/2/1993 | 10.80% | 6.60% | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | 3.45% |
| 11/18/1994 | 11.20% | 7.46% | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | 3.55% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/9/1995 | 11.25% | 7.60% | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | 4.47% |
| 12/18/1996 | 11.75% | 6.84% | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | 4.98% |
| 2/20/1997 | 11.80% | 6.82% | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | 7.00% |
| 1/22/2002 | 10.00% | 5.50% | 4.50% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 3/27/2002 | 10.10% | 5.45% | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | 5.56% |
| 1/13/2004 | 12.00% | 4.95% | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | 6.43% |
| 12/29/2004 | 9.85% | 5.08% | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | 5.58% |
| 4/26/2006 | 10.60% | 4.64% | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | 6.91% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 6/6/2006 | 10.00% | 4.75% | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | 5.45% |
| 5/22/2007 | 10.20% | 4.80% | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | 5.69% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 11/13/2008 | 10.55% | 4.45% | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | 6.68% |
| 10/23/2009 | 10.88% | 4.06% | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | 5.42% |
| 8/25/2010 | 9.90% | 4.37% | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | 5.68% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/16/2010 | 10.00% | 4.32% | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | 5.89% |
| 2/25/2011 | 10.00% | 4.14% | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | 7.06% |
| 4/4/2012 | 10.00% | 3.29% | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | 6.96% |
| 7/9/2012 | 10.20% | 3.03% | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | 6.86% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 9/19/2012 | 9.80% | 2.94% | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | 7.58% |
| 12/21/2012 | 10.20% | 2.87% | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | 6.73% |
| 6/30/2014 | 9.55% | 3.64% | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | 6.30% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 8/20/2014 | 9.75% | 3.56% | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | 6.77% |
| 4/23/2015 | 10.20% | 2.87% | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | 7.05% |
| 9/30/2016 | 9.90% | 2.53% | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | 7.50% |
| 2/15/2017 | 9.60% | 2.62% | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | 7.53% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 4/12/2017 | 9.40% | 2.74% | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | 7.12% |
| 12/5/2017 | 9.50% | 2.88% | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | 6.53% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | 6.81% |

| Date of Electric Rate Case | Return on Equity | 30-Year Treasury Yield | Risk Premium |
|---|---|---|---|
| 8/12/2019 | 9.60% | 2.89% | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | 7.40% |
| 11/7/2019 | 9.35% | 2.58% | 6.77% |
| 11/29/2019 | 9.50% | 2.52% | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | 7.04% |
| 1/8/2020 | 10.02% | 2.43% | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | 7.63% |
| | | Average | 4.72% |
| | | Count | 1625 |

Expected Earnings Analysis

| | | [1] | [2] | [3] | [4] | [5] | [6] |
|---|---|---|---|---|---|---|---|
| | | Expected ROE | Shares Outstanding | | | Adjustment | Adjusted |
| Company | Ticker | 2022-2024/ 2023-2025 | 2020 | 2022-2024/ 2023-2025 | % Increase | Factor | ROE |
| ALLETE, Inc. | ALE | 8.50% | 52.00 | 53.00 | 0.38% | 1.002 | 8.52% |
| Alliant Energy Corporation | LNT | 10.50% | 248.00 | 260.00 | 0.95% | 1.005 | 10.55% |
| Ameren Corporation | AEE | 10.00% | 254.00 | 275.00 | 1.60% | 1.008 | 10.08% |
| American Electric Power Company, Inc. | AEP | 10.50% | 495.00 | 530.00 | 1.38% | 1.007 | 10.57% |
| Avangrid, Inc. | AGR | 6.00% | 309.00 | 309.00 | 0.00% | 1.000 | 6.00% |
| Avista | AVA | 8.00% | 68.00 | 71.00 | 1.09% | 1.005 | 8.04% |
| CMS Energy Corporation | CMS | 13.50% | 287.00 | 300.00 | 0.89% | 1.004 | 13.56% |
| DTE Energy Company | DTE | 10.50% | 194.00 | 206.00 | 1.21% | 1.006 | 10.56% |
| Evergy, Inc | EVRG | 8.50% | 227.00 | 227.00 | 0.00% | 1.000 | 8.50% |
| Hawaiian Electric Industries, Inc. | HE | 9.00% | 110.00 | 113.00 | 0.67% | 1.003 | 9.03% |
| NextEra Energy, Inc. | NEE | 13.00% | 489.00 | 495.00 | 0.24% | 1.001 | 13.02% |
| NorthWestern Corporation | NWE | 9.00% | 50.90 | 51.60 | 0.34% | 1.002 | 9.02% |
| OGE Energy Corp. | OGE | 11.00% | 200.00 | 200.00 | 0.00% | 1.000 | 11.00% |
| Otter Tail Corporation | OTTR | 11.50% | 41.00 | 41.50 | 0.24% | 1.001 | 11.51% |
| Pinnacle West Capital Corporation | PNW | 10.00% | 113.50 | 118.00 | 0.98% | 1.005 | 10.05% |
| PNM Resources, Inc. | PNM | 9.00% | 79.65 | 90.00 | 3.10% | 1.015 | 9.14% |
| Portland General Electric Company | POR | 9.00% | 89.55 | 90.00 | 0.13% | 1.001 | 9.01% |
| Southern Company | SO | 13.00% | 1050.00 | 1080.00 | 0.57% | 1.003 | 13.04% |
| WEC Energy Group, Inc. | WEC | 12.50% | 315.50 | 315.50 | 0.00% | 1.000 | 12.50% |
| Xcel Energy Inc. | XEL | 10.50% | 539.00 | 546.00 | 0.32% | 1.002 | 10.52% |
| | | | | | | Median | 10.30% |
| | | | | | | Average | 10.21% |

Notes:

[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals =([3] / [2])^(1/4)-1; ([3] / [2])^(1/5)-1
[5] Equals (2 x (1 + [4])) / (2 + [4])
[6] Equals [1] x [5]

Proxy Group Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 58.68% | 59.66% | 59.53% | 59.12% | 58.50% | 58.84% | 63.09% | 62.51% | 59.99% |
| Alliant Energy Corporation | LNT | 51.73% | 50.38% | 53.18% | 53.11% | 51.13% | 51.00% | 49.74% | 49.77% | 51.26% |
| Ameren Corporation | AEE | 53.67% | 53.03% | 52.81% | 52.69% | 53.22% | 52.01% | 53.04% | 52.65% | 52.89% |
| American Electric Power Company, Inc. | AEP | 49.91% | 48.80% | 49.62% | 49.40% | 48.68% | 48.52% | 48.60% | 48.91% | 49.06% |
| Avangrid, Inc. | AGR | 54.38% | 56.33% | 56.51% | 55.72% | 56.13% | 54.93% | 56.55% | 55.69% | 55.78% |
| Avista Corporation | AVA | 55.80% | 56.32% | 56.10% | 55.09% | 55.75% | 55.76% | 56.34% | 55.76% | 55.86% |
| CMS Energy Corporation | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| DTE Energy Company | DTE | 49.40% | 48.76% | 48.69% | 50.96% | 49.97% | 49.23% | 51.12% | 51.02% | 49.89% |
| Evergy, Inc. | EVRG | 60.28% | 60.51% | 58.16% | 59.56% | 59.86% | 58.51% | 58.73% | 58.62% | 59.28% |
| Hawaiian Electric Industries, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| NextEra Energy, Inc. | NEE | 56.15% | 61.22% | 61.05% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 61.20% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| OGE Energy Corp. | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Corporation | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Pinnacle West Capital Corporation | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| PNM Resources, Inc. | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Southern Company | SO | 52.36% | 52.93% | 52.80% | 54.21% | 51.50% | 50.31% | 49.98% | 47.67% | 51.47% |
| Wisconsin Energy Corporation | WEC | 55.79% | 56.71% | 55.73% | 53.46% | 58.30% | 57.72% | 61.62% | 54.62% | 56.74% |
| Xcel Energy Inc. | XEL | 53.98% | 54.70% | 54.51% | 54.22% | 53.37% | 53.63% | 54.15% | 53.95% | 54.06% |
| Mean | | 53.59% | 53.81% | 53.79% | 53.75% | 53.87% | 53.32% | 53.90% | 53.52% | 53.69% |
| | | | | | | | | | | 45.65% |
| | | | | | | | | | | 61.20% |

Operating Company Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 59.33% | 60.94% | 60.87% | 61.39% | 60.43% | 60.33% | 60.38% | 60.04% | 60.46% |
| Superior Water, Light and Power Company | ALE | 58.03% | 58.38% | 58.19% | 56.86% | 56.58% | 57.34% | 65.80% | 64.99% | 59.52% |
| Interstate Power and Light Company | LNT | 50.06% | 51.76% | 53.33% | 53.52% | 49.64% | 50.47% | 49.92% | 50.31% | 51.13% |
| Wisconsin Power and Light Company | LNT | 53.40% | 49.01% | 53.03% | 52.69% | 52.62% | 51.52% | 49.57% | 49.23% | 51.38% |
| Ameren Illinois Company | AEE | 54.46% | 54.05% | 53.65% | 52.86% | 53.18% | 52.74% | 54.24% | 53.38% | 53.57% |
| Union Electric Company | AEE | 52.88% | 52.00% | 51.96% | 52.52% | 53.26% | 51.28% | 51.84% | 51.92% | 52.21% |
| AEP Texas Inc. | AEP | 46.97% | 46.32% | 47.54% | 45.38% | 43.80% | 43.20% | 46.75% | 45.14% | 45.64% |
| Appalachian Power Company | AEP | 48.74% | 48.19% | 47.77% | 49.51% | 49.30% | 48.93% | 49.35% | 48.72% | 48.81% |
| Indiana Michigan Power Company | AEP | 46.51% | 45.83% | 45.43% | 44.62% | 44.53% | 44.15% | 46.64% | 46.33% | 45.50% |
| Kentucky Power Company | AEP | 46.94% | 46.50% | 46.42% | 45.72% | 45.28% | 44.89% | 44.40% | 43.52% | 45.46% |
| Kingsport Power Company | AEP | 54.24% | 50.18% | 51.54% | 50.79% | 50.71% | 47.69% | 47.28% | 46.53% | 49.87% |
| Ohio Power Company | AEP | 53.63% | 52.92% | 58.86% | 57.80% | 56.85% | 57.11% | 52.91% | 58.63% | 56.09% |
| Public Service Company of Oklahoma | AEP | 49.89% | 48.02% | 47.19% | 49.16% | 49.55% | 48.59% | 48.10% | 48.50% | 48.62% |
| Southwestern Electric Power Company | AEP | 48.63% | 47.45% | 47.59% | 46.97% | 43.43% | 47.91% | 47.72% | 48.52% | 47.28% |
| Wheeling Power Company | AEP | 53.66% | 53.83% | 54.27% | 54.62% | 54.70% | 54.19% | 54.27% | 54.26% | 54.23% |
| Central Maine Power Company | AGR | 62.19% | 61.96% | 63.51% | 63.21% | 64.17% | 63.53% | 64.18% | 63.82% | 63.32% |
| New York State Electric & Gas Corporation | AGR | 48.79% | 55.84% | 55.93% | 54.30% | 53.95% | 50.99% | 54.51% | 53.30% | 53.45% |
| Rochester Gas and Electric Corporation | AGR | 50.50% | 50.25% | 49.96% | 48.89% | 48.16% | 47.77% | 50.80% | 49.63% | 49.50% |
| United Illuminating Company | AGR | 56.05% | 57.26% | 56.65% | 56.46% | 58.23% | 57.43% | 56.70% | 56.00% | 56.85% |
| Alaska Electric Light and Power Company | AVA | 61.28% | 61.24% | 61.02% | 60.29% | 61.94% | 61.78% | 61.53% | 60.77% | 61.23% |
| Avista Corporation | AVA | 50.33% | 51.40% | 51.18% | 49.89% | 49.55% | 49.74% | 51.16% | 50.75% | 50.50% |
| Consumers Energy Company | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| DTE Electric Company | DTE | 49.40% | 48.76% | 48.69% | 50.96% | 49.97% | 49.23% | 51.12% | 51.02% | 49.89% |
| Evergy Kansas South, Inc. | EVRG | 81.84% | 81.49% | 75.13% | 74.97% | 74.91% | 74.45% | 74.29% | 74.18% | 76.41% |
| Evergy Metro, Inc. | EVRG | 50.43% | 49.62% | 46.04% | 49.49% | 49.50% | 48.88% | 49.25% | 49.15% | 49.05% |
| Evergy Missouri West, Inc. | EVRG | 51.18% | 51.74% | 52.68% | 54.71% | 55.70% | 52.03% | 52.63% | 52.40% | 52.88% |
| Westar Energy (KPL) | EVRG | 57.66% | 59.18% | 58.80% | 59.08% | 59.34% | 58.68% | 58.75% | 58.74% | 58.78% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Florida Power & Light Company | NEE | 59.78% | 61.30% | 64.03% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 62.03% |
| Gulf Power Company | NEE | 52.52% | 61.15% | 58.06% | NA | NA | NA | NA | NA | 57.24% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| Oklahoma Gas and Electric Company | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Power Company | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Arizona Public Service Company | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| Public Service Company of New Mexico | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Alabama Power Company | SO | 51.45% | 52.54% | 52.23% | 47.77% | 48.13% | 47.51% | 48.86% | 47.07% | 49.44% |
| Georgia Power Company | SO | 55.38% | 56.39% | 56.43% | 59.02% | 57.27% | 54.97% | 53.81% | 50.06% | 55.42% |
| Gulf Power Company | SO | NA | NA | NA | 59.73% | 55.34% | 54.90% | 54.27% | 54.19% | 55.69% |
| Mississippi Power Company | SO | 50.23% | 49.87% | 49.73% | 50.35% | 45.28% | 43.87% | 43.00% | 39.34% | 46.46% |
| Upper Michigan Energy Resources Corporation | WEC | 56.09% | 54.45% | 52.54% | 47.01% | 55.08% | 54.53% | 70.04% | 49.85% | 54.95% |
| Wisconsin Electric Power Company | WEC | 56.92% | 56.64% | 55.78% | 56.03% | 59.25% | 59.09% | 56.47% | 55.94% | 57.01% |
| Wisconsin Public Service Corporation | WEC | 54.37% | 59.04% | 58.88% | 57.33% | 60.59% | 59.53% | 58.35% | 58.06% | 58.27% |
| Northern States Power Company - MN | XEL | 51.79% | 53.66% | 53.64% | 52.81% | 52.64% | 52.61% | 52.59% | 52.38% | 52.77% |
| Northern States Power Company - WI | XEL | 53.56% | 53.49% | 53.59% | 53.60% | 48.45% | 53.85% | 53.79% | 53.36% | 52.96% |
| Public Service Company of Colorado | XEL | 56.35% | 57.53% | 56.68% | 56.31% | 56.08% | 54.17% | 56.67% | 56.50% | 56.29% |
| Southwestern Public Service Company | XEL | 54.21% | 54.14% | 54.13% | 54.17% | 56.29% | 53.88% | 53.54% | 53.55% | 54.24% |
| Mean | | 53.68% | 53.94% | 53.92% | 53.66% | 53.58% | 53.04% | 53.71% | 53.03% | 53.63% |
| | | | | | | | | | | 45.46% |
| | | | | | | | | | | 76.41% |

Source: S&P Global Market Intelligence

Proxy Group Capital Structure

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 41.32% | 40.34% | 40.47% | 40.88% | 41.50% | 41.16% | 36.91% | 37.49% | 40.01% |
| Alliant Energy Corporation | LNT | 48.27% | 49.62% | 46.82% | 46.89% | 48.87% | 49.00% | 50.26% | 50.23% | 48.74% |
| Ameren Corporation | AEE | 46.33% | 46.97% | 47.19% | 47.31% | 46.78% | 47.99% | 46.96% | 47.35% | 47.11% |
| American Electric Power Company, Inc. | AEP | 50.09% | 51.20% | 50.38% | 50.60% | 51.32% | 51.48% | 51.40% | 51.09% | 50.94% |
| Avangrid, Inc. | AGR | 45.62% | 43.67% | 43.49% | 44.28% | 43.87% | 45.07% | 43.45% | 44.31% | 44.22% |
| Avista Corporation | AVA | 44.20% | 43.68% | 43.90% | 44.91% | 44.25% | 44.24% | 43.66% | 44.24% | 44.14% |
| CMS Energy Corporation | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| DTE Energy Company | DTE | 50.60% | 51.24% | 51.31% | 49.04% | 50.03% | 50.77% | 48.88% | 48.98% | 50.11% |
| Evergy, Inc. | EVRG | 39.72% | 39.49% | 41.84% | 40.44% | 40.14% | 41.49% | 41.27% | 41.38% | 40.72% |
| Hawaiian Electric Industries, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| NextEra Energy, Inc. | NEE | 43.85% | 38.78% | 38.95% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 38.80% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| OGE Energy Corp. | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Corporation | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Pinnacle West Capital Corporation | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| PNM Resources, Inc. | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Southern Company | SO | 47.64% | 47.07% | 47.20% | 45.79% | 48.50% | 49.69% | 50.02% | 52.33% | 48.53% |
| Wisconsin Energy Corporation | WEC | 44.21% | 43.29% | 44.27% | 46.54% | 41.70% | 42.28% | 38.38% | 45.38% | 43.26% |
| Xcel Energy Inc. | XEL | 46.02% | 45.30% | 45.49% | 45.78% | 46.63% | 46.37% | 45.85% | 46.05% | 45.94% |
| Mean | | 46.41% | 46.19% | 46.21% | 46.25% | 46.13% | 46.68% | 46.10% | 46.48% | 46.31% |

Operating Company Capital Structure

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 40.67% | 39.06% | 39.13% | 38.61% | 39.57% | 39.67% | 39.62% | 39.96% | 39.54% |
| Superior Water, Light and Power Company | ALE | 41.97% | 41.62% | 41.81% | 43.14% | 43.42% | 42.66% | 34.20% | 35.01% | 40.48% |
| Interstate Power and Light Company | LNT | 49.94% | 48.24% | 46.67% | 46.48% | 50.36% | 49.53% | 50.08% | 49.69% | 48.87% |
| Wisconsin Power and Light Company | LNT | 46.60% | 50.99% | 46.97% | 47.31% | 47.38% | 48.48% | 50.43% | 50.77% | 48.62% |
| Ameren Illinois Company | AEE | 45.54% | 45.95% | 46.35% | 47.14% | 46.82% | 47.26% | 45.76% | 46.62% | 46.43% |
| Union Electric Company | AEE | 47.12% | 48.00% | 48.04% | 47.48% | 46.74% | 48.72% | 48.16% | 48.08% | 47.79% |
| AEP Texas Inc. | AEP | 53.03% | 53.68% | 52.46% | 54.62% | 56.20% | 56.80% | 53.25% | 54.86% | 54.36% |
| Appalachian Power Company | AEP | 51.26% | 51.81% | 52.23% | 50.49% | 50.70% | 51.07% | 50.65% | 51.28% | 51.19% |
| Indiana Michigan Power Company | AEP | 53.49% | 54.17% | 54.57% | 55.38% | 55.47% | 55.85% | 53.36% | 53.67% | 54.50% |
| Kentucky Power Company | AEP | 53.06% | 53.50% | 53.58% | 54.28% | 54.72% | 55.11% | 55.60% | 56.48% | 54.54% |
| Kingsport Power Company | AEP | 45.76% | 49.82% | 48.46% | 49.21% | 49.29% | 52.31% | 52.72% | 53.47% | 50.13% |
| Ohio Power Company | AEP | 46.37% | 47.08% | 41.14% | 42.20% | 43.15% | 42.89% | 47.09% | 41.37% | 43.91% |
| Public Service Company of Oklahoma | AEP | 50.11% | 51.98% | 52.81% | 50.84% | 50.45% | 51.41% | 51.90% | 51.50% | 51.38% |
| Southwestern Electric Power Company | AEP | 51.37% | 52.55% | 52.41% | 53.03% | 56.57% | 52.09% | 52.28% | 51.48% | 52.72% |
| Wheeling Power Company | AEP | 46.34% | 46.17% | 45.73% | 45.38% | 45.30% | 45.81% | 45.73% | 45.74% | 45.77% |
| Central Maine Power Company | AGR | 37.81% | 38.04% | 36.49% | 36.79% | 35.83% | 36.47% | 35.82% | 36.18% | 36.68% |
| New York State Electric & Gas Corporation | AGR | 51.21% | 44.16% | 44.07% | 45.70% | 46.05% | 49.01% | 45.49% | 46.70% | 46.55% |
| Rochester Gas and Electric Corporation | AGR | 49.50% | 49.75% | 50.04% | 51.11% | 51.84% | 52.23% | 49.20% | 50.37% | 50.50% |
| United Illuminating Company | AGR | 43.95% | 42.74% | 43.35% | 43.54% | 41.77% | 42.57% | 43.30% | 44.00% | 43.15% |
| Alaska Electric Light and Power Company | AVA | 38.72% | 38.76% | 38.98% | 39.71% | 38.06% | 38.22% | 38.47% | 39.23% | 38.77% |
| Avista Corporation | AVA | 49.67% | 48.60% | 48.82% | 50.11% | 50.45% | 50.26% | 48.84% | 49.25% | 49.50% |
| Consumers Energy Company | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| DTE Electric Company | DTE | 50.60% | 51.24% | 51.31% | 49.04% | 50.03% | 50.77% | 48.88% | 48.98% | 50.11% |
| Evergy Kansas South, Inc. | EVRG | 18.16% | 18.51% | 24.87% | 25.03% | 25.09% | 25.55% | 25.71% | 25.82% | 23.59% |
| Evergy Metro, Inc. | EVRG | 49.57% | 50.38% | 53.96% | 50.51% | 50.50% | 51.12% | 50.75% | 50.85% | 50.95% |
| Evergy Missouri West, Inc. | EVRG | 48.82% | 48.26% | 47.32% | 45.29% | 44.30% | 47.97% | 47.37% | 47.60% | 47.12% |
| Westar Energy (KPL) | EVRG | 42.34% | 40.82% | 41.20% | 40.92% | 40.66% | 41.32% | 41.25% | 41.26% | 41.22% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Florida Power & Light Company | NEE | 40.22% | 38.70% | 35.97% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 37.97% |
| Gulf Power Company | NEE | 47.48% | 38.85% | 41.94% | NA | NA | NA | NA | NA | 42.76% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| Oklahoma Gas and Electric Company | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Power Company | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Arizona Public Service Company | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| Public Service Company of New Mexico | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Alabama Power Company | SO | 48.55% | 47.46% | 47.77% | 52.23% | 51.87% | 52.49% | 51.14% | 52.93% | 50.56% |
| Georgia Power Company | SO | 44.62% | 43.61% | 43.57% | 40.98% | 42.73% | 45.03% | 46.19% | 49.94% | 44.58% |
| Gulf Power Company | SO | NA | NA | NA | 40.27% | 44.66% | 45.10% | 45.73% | 45.81% | 44.31% |
| Mississippi Power Company | SO | 49.77% | 50.13% | 50.27% | 49.65% | 54.72% | 56.13% | 57.00% | 60.66% | 53.54% |
| Upper Michigan Energy Resources Corporation | WEC | 43.91% | 45.55% | 47.46% | 52.99% | 44.92% | 45.47% | 29.96% | 50.15% | 45.05% |
| Wisconsin Electric Power Company | WEC | 43.08% | 43.36% | 44.22% | 43.97% | 40.75% | 40.91% | 43.53% | 44.06% | 42.99% |
| Wisconsin Public Service Corporation | WEC | 45.63% | 40.96% | 41.12% | 42.67% | 39.41% | 40.47% | 41.65% | 41.94% | 41.73% |
| Northern States Power Company - MN | XEL | 48.21% | 46.34% | 46.36% | 47.19% | 47.36% | 47.39% | 47.41% | 47.62% | 47.23% |
| Northern States Power Company - WI | XEL | 46.44% | 46.51% | 46.41% | 46.40% | 51.55% | 46.15% | 46.21% | 46.64% | 47.04% |
| Public Service Company of Colorado | XEL | 43.65% | 42.47% | 43.32% | 43.69% | 43.92% | 45.83% | 43.33% | 43.50% | 43.71% |
| Southwestern Public Service Company | XEL | 45.79% | 45.86% | 45.87% | 45.83% | 43.71% | 46.12% | 46.46% | 46.45% | 45.76% |
| Mean | | 46.32% | 46.06% | 46.08% | 46.34% | 46.42% | 46.96% | 46.29% | 46.97% | 46.37% |

2015-2020 Authorized Returns on Equity, Vertically Integrated Electric Utitlity Rate Cases

| State | Utility | Parent Company Ticker | Case Identification | Date Authorized | Authorized ROE |
|---|---|---|---|---|---|
| Wyoming | PacifiCorp | BRK.A | D-20000-446-ER-14 | 1/23/2015 | 9.50 |
| Colorado | Public Service Co. of CO | XEL | D-14AL-0660E | 2/24/2015 | 9.83 |
| Washington | PacifiCorp | BRK.A | D-UE-140762 | 3/25/2015 | 9.50 |
| Minnesota | Northern States Power Co. - MN | XEL | D-E-002/GR-13-868 | 3/26/2015 | 9.72 |
| Michigan | Wisconsin Public Service Corp. | WEC | C-U-17669 | 4/23/2015 | 10.20 |
| Missouri | Union Electric Co. | AEE | C-ER-2014-0258 | 4/29/2015 | 9.53 |
| West Virginia | Appalachian Power Co. | AEP | C-14-1152-E-42T | 5/26/2015 | 9.75 |
| Missouri | Kansas City Power & Light | GXP | C-ER-2014-0370 | 9/2/2015 | 9.50 |
| Kansas | Kansas City Power & Light | GXP | D-15-KCPE-116-RTS | 9/10/2015 | 9.30 |
| Wisconsin | Wisconsin Public Service Corp. | WEC | D-6690-UR-124 (Elec) | 11/19/2015 | 10.00 |
| Michigan | Consumers Energy Co. | CMS | C-U-17735 | 11/19/2015 | 10.30 |
| Wisconsin | Northern States Power Co - WI | XEL | D-4220-UR-121 (Elec) | 12/3/2015 | 10.00 |
| Michigan | DTE Electric Co. | DTE | C-U-17767 | 12/11/2015 | 10.30 |
| Oregon | Portland General Electric Co. | POR | D-UE-294 | 12/15/2015 | 9.60 |
| Texas | Southwestern Public Service Co | XEL | D-43695 | 12/17/2015 | 9.70 |
| Idaho | Avista Corp. | AVA | C-AVU-E-15-05 | 12/18/2015 | 9.50 |
| Wyoming | PacifiCorp | BRK.A | D-20000-469-ER-15 | 12/30/2015 | 9.50 |
| Washington | Avista Corp. | AVA | D-UE-150204 | 1/6/2016 | 9.50 |
| Arkansas | Entergy Arkansas Inc. | ETR | D-15-015-U | 2/23/2016 | 9.75 |
| Indiana | Indianapolis Power & Light Co. | AES | Ca-44576 | 3/16/2016 | 9.85 |
| New Mexico | El Paso Electric Co. | EE | C-15-00127-UT | 6/8/2016 | 9.48 |
| Indiana | Northern IN Public Svc Co. | NI | Ca-44688 | 7/18/2016 | 9.98 |
| Tennessee | Kingsport Power Company | AEP | D-16-00001 | 8/9/2016 | 9.85 |
| Arizona | UNS Electric Inc. | FTS | D-E-04204A-15-0142 | 8/18/2016 | 9.50 |
| Washington | PacifiCorp | BRK.A | D-UE-152253 | 9/1/2016 | 9.50 |
| Michigan | Upper Peninsula Power Co. | - | C-U-17895 | 9/8/2016 | 10.00 |
| New Mexico | Public Service Co. of NM | PNM | C-15-00261-UT | 9/28/2016 | 9.58 |
| Wisconsin | Madison Gas and Electric Co. | MGEE | D-3270-UR-121 (Elec) | 11/9/2016 | 9.80 |
| Oklahoma | Public Service Co. of OK | AEP | Ca-PUD201500208 | 11/10/2016 | 9.50 |
| Wisconsin | Wisconsin Power and Light Co | LNT | D-6680-UR-120 (Elec) | 11/18/2016 | 10.00 |
| Florida | Florida Power & Light Co. | NEE | D-160021-EI | 11/29/2016 | 10.55 |
| California | Liberty Utilities CalPeco Ele | AQN | A-15-05-008 | 12/1/2016 | 10.00 |
| South Carolina | Duke Energy Progress LLC | DUK | D-2016-227-E | 12/7/2016 | 10.10 |
| Colorado | Black Hills Colorado Electric | BKH | D-16AL-0326E | 12/19/2016 | 9.37 |
| North Carolina | Virginia Electric & Power Co. | D | D-E-22, Sub 532 | 12/22/2016 | 9.90 |
| Nevada | Sierra Pacific Power Co. | BRK.A | D-16-06006 | 12/22/2016 | 9.60 |
| Idaho | Avista Corp. | AVA | C-AVU-E-16-03 | 12/28/2016 | 9.50 |

| State | Utility | Parent Company Ticker | Case Identification | Date Authorized | Authorized ROE |
|---|---|---|---|---|---|
| Wyoming | MDU Resources Group Inc. | MDU | D-2004-117-ER-16 | 1/18/2017 | 9.45 |
| Michigan | DTE Electric Co. | DTE | C-U-18014 | 1/31/2017 | 10.10 |
| Arizona | Tucson Electric Power Co. | FTS | D-E-01933A-15-0322 | 2/24/2017 | 9.75 |
| Michigan | Consumers Energy Co. | CMS | C-U-17990 | 2/28/2017 | 10.10 |
| Minnesota | Otter Tail Power Co. | OTTR | D-E-017/GR-15-1033 | 3/2/2017 | 9.41 |
| Oklahoma | Oklahoma Gas and Electric Co. | OGE | Ca-PUD201500273 | 3/20/2017 | 9.50 |
| Florida | Gulf Power Co. | SO | D-160186-EI | 4/4/2017 | 10.25 |
| Missouri | Kansas City Power & Light | GXP | C-ER-2016-0285 | 5/3/2017 | 9.50 |
| Minnesota | Northern States Power Co. - MN | XEL | D-E-002/GR-15-826 | 5/11/2017 | 9.20 |
| Arkansas | Oklahoma Gas and Electric Co. | OGE | D-16-052-U | 5/18/2017 | 9.50 |
| North Dakota | MDU Resources Group Inc. | MDU | C-PU-16-666 | 6/16/2017 | 9.65 |
| Kentucky | Kentucky Utilities Co. | PPL | C-2016-00370 | 6/22/2017 | 9.70 |
| Kentucky | Louisville Gas & Electric Co. | PPL | C-2016-00371 (elec.) | 6/22/2017 | 9.70 |
| Arizona | Arizona Public Service Co. | PNW | D-E-01345A-16-0036 | 8/15/2017 | 10.00 |
| California | San Diego Gas & Electric Co. | SRE | Advice No. 3120-E | 10/26/2017 | 10.20 |
| California | Pacific Gas and Electric Co. | PCG | Advise No. 3887-G/5148-E | 10/26/2017 | 10.25 |
| California | Southern California Edison Co. | EIX | Advice No. 3665-E | 10/26/2017 | 10.30 |
| Florida | Tampa Electric Co. | EMA | D-20170210-EI | 11/6/2017 | 10.25 |
| Alaska | Alaska Electric Light Power | AVA | D-U-16-086 | 11/15/2017 | 11.95 |
| Washington | Puget Sound Energy Inc. | | D-UE-170033 | 12/5/2017 | 9.50 |
| Wisconsin | Northern States Power Co - WI | XEL | D-4220-UR-123 (Elec) | 12/7/2017 | 9.80 |
| Texas | Southwestern Electric Power Co | AEP | D-46449 | 12/14/2017 | 9.60 |
| Texas | El Paso Electric Co. | EE | D-46831 | 12/14/2017 | 9.65 |
| Oregon | Portland General Electric Co. | POR | D-UE-319 | 12/18/2017 | 9.50 |
| New Mexico | Public Service Co. of NM | PNM | C-16-00276-UT | 12/20/2017 | 9.58 |
| Vermont | Green Mountain Power Corp. | | C-17-3112-INV | 12/21/2017 | 9.10 |
| Idaho | Avista Corp. | AVA | D-AVU-E-17-01 | 12/28/2017 | 9.50 |
| Nevada | Nevada Power Co. | BRK.A | D-17-06003 | 12/29/2017 | 9.51 |
| Kentucky | Kentucky Power Co. | AEP | C-2017-00179 | 1/18/2018 | 9.70 |
| Oklahoma | Public Service Co. of OK | AEP | Ca-PUD201700151 | 1/31/2018 | 9.30 |
| Iowa | Interstate Power & Light Co. | LNT | D-RPU-2017-0001 | 2/2/2018 | 9.98 |
| North Carolina | Duke Energy Progress LLC | DUK | D-E-2, Sub 1142 | 2/23/2018 | 9.90 |
| Minnesota | ALLETE (Minnesota Power) | ALE | D-E-015/GR-16-664 | 3/12/2018 | 9.25 |
| Michigan | Consumers Energy Co. | CMS | C-U-18322 | 3/29/2018 | 10.00 |
| Michigan | Indiana Michigan Power Co. | AEP | C-U-18370 | 4/12/2018 | 9.90 |
| Kentucky | Duke Energy Kentucky Inc. | DUK | C-2017-00321 | 4/13/2018 | 9.73 |
| Michigan | DTE Electric Co. | DTE | C-U-18255 | 4/18/2018 | 10.00 |
| Washington | Avista Corp. | AVA | D-UE-170485 | 4/26/2018 | 9.50 |
| Indiana | Indiana Michigan Power Co. | AEP | Ca-44967 | 5/30/2018 | 9.95 |
| Hawaii | Hawaiian Electric Co. | HE | D-2016-0328 | 6/22/2018 | 9.50 |
| North Carolina | Duke Energy Carolinas LLC | DUK | D-E-7, Sub 1146 | 6/22/2018 | 9.90 |
| Hawaii | Hawaii Electric Light Co | HE | D-2015-0170 | 6/29/2018 | 9.50 |
| New Mexico | Southwestern Public Service Co | XEL | C-17-00255-UT | 9/5/2018 | 9.56 |
| Wisconsin | Wisconsin Power and Light Co | LNT | D-6680-UR-121 (Elec) | 9/14/2018 | 10.00 |
| Wisconsin | Madison Gas and Electric Co. | MGEE | D-3270-UR-122 (Elec) | 9/20/2018 | 9.80 |
| North Dakota | Otter Tail Power Co. | OTTR | C-PU-17-398 | 9/26/2018 | 9.77 |
| Kansas | Evergy Kansas Central Inc. | EVRG | D-18-WSEE-328-RTS | 9/27/2018 | 9.30 |
| Indiana | Indianapolis Power & Light Co. | AES | Ca-45029 | 10/31/2018 | 9.99 |
| Kansas | Evergy Metro Inc | EVRG | D-18-KCPE-480-RTS | 12/13/2018 | 9.30 |
| Oregon | Portland General Electric Co. | POR | D-UE-335 | 12/14/2018 | 9.50 |
| Vermont | Green Mountain Power Corp. | | C-18-0974-TF | 12/21/2018 | 9.30 |

| State | Utility | Parent Company Ticker | Case Identification | Date Authorized | Authorized ROE |
|---|---|---|---|---|---|
| Michigan | Consumers Energy Co. | CMS | C-U-20134 | 1/9/2019 | 10.00 |
| West Virginia | Appalachian Power Co. | AEP | C-18-0646-E-42T | 2/27/2019 | 9.75 |
| Oklahoma | Public Service Co. of OK | AEP | Ca-PUD201800097 | 3/14/2019 | 9.40 |
| Kentucky | Kentucky Utilities Co. | PPL | C-2018-00294 | 4/30/2019 | 9.73 |
| Kentucky | Louisville Gas & Electric Co. | PPL | C-2018-00295 (elec.) | 4/30/2019 | 9.73 |
| South Carolina | Duke Energy Carolinas LLC | DUK | D-2018-319-E | 5/1/2019 | 9.50 |
| Michigan | DTE Electric Co. | DTE | C-U-20162 | 5/2/2019 | 10.00 |
| South Carolina | Duke Energy Progress LLC | DUK | D-2018-318-E | 5/8/2019 | 9.50 |
| South Dakota | Otter Tail Power Co. | OTTR | D-EL18-021 | 5/14/2019 | 8.75 |
| Hawaii | Maui Electric Company Ltd | HE | D-2017-0150 | 5/16/2019 | 9.50 |
| Michigan | Upper Peninsula Power Co. | | C-U-20276 | 5/23/2019 | 9.90 |
| Vermont | Green Mountain Power Corp. | | C-19-1932-TF | 8/29/2019 | 9.06 |
| Wisconsin | Northern States Power Co - WI | XEL | D- 4220-UR-124 (Elec) | 9/4/2019 | 10.00 |
| Wisconsin | Wisconsin Electric Power Co. | WEC | D-05-UR-109 (WEP-Elec) | 10/31/2019 | 10.00 |
| Wisconsin | Wisconsin Public Service Corp. | WEC | D-6690-UR-126 (Elec) | 10/31/2019 | 10.00 |
| Louisiana | Entergy New Orleans LLC | ETR | D-UD-18-07 (elec.) | 11/7/2019 | 9.35 |
| Idaho | Avista Corp. | AVA | C-AVU-E-1904 | 11/29/2019 | 9.50 |
| Indiana | Northern IN Public Svc Co. | NI | Ca-45159 | 12/4/2019 | 9.75 |
| Georgia | Georgia Power Co. | SO | D-42516 | 12/17/2019 | 10.50 |
| California | San Diego Gas & Electric Co. | SRE | A-19-04-017 (Elec) | 12/19/2019 | 10.20 |
| California | Pacific Gas and Electric Co. | PCG | A-19-04-015 | 12/19/2019 | 10.25 |
| California | Southern California Edison Co. | EIX | A-19-04-014 | 12/19/2019 | 10.30 |
| Arkansas | Southwestern Electric Power Co | AEP | D-19-008-U | 12/20/2019 | 9.45 |
| Montana | NorthWestern Corp. | NWE | D2018.2.12 | 12/20/2019 | 9.65 |
| Nevada | Sierra Pacific Power Co. | BRK.A | D-19-06002 | 12/24/2019 | 9.50 |
| Iowa | Interstate Power & Light Co. | LNT | D-RPU-2019-0001 | 1/8/2020 | 10.02 |
| Michigan | Indiana Michigan Power Co. | AEP | C-U-20359 | 1/23/2020 | 9.86 |
| California | PacifiCorp | BRK.A | A-18-04-002 | 2/6/2020 | 10.00 |
| Colorado | Public Service Co. of CO | XEL | D-19AL-0268E | 2/11/2020 | 9.30 |
| North Carolina | Virginia Electric & Power Co. | D | E-22, Sub 562 | 2/24/2020 | 9.75 |
| Indiana | Indiana Michigan Power Co. | AEP | Ca-45235 | 3/11/2020 | 9.70 |
| Washington | Avista Corp. | AVA | D-UE-190334 | 3/25/2020 | 9.40 |

| | |
|---|---|
| Average | 9.75 |
| Median | 9.71 |
| Minimum | 8.75 |
| Maximum | 11.95 |
| Count >=10% 2017-2020 | 23 |
| Count >=10% 2019-2020 | 11 |
| 2019-2020 Average | 9.73 |
| 2019-2020 Median | 9.74 |

Source: Regulatory Research Associates

Alternative Bond Yield Plus Risk Premium Analyses

| [1] Constant | [2] LN(30-Year Treasury) | [3] VIX |
|---|---|---|
| -0.0275 | -0.0258 | 0.0003 |

| | 30-Yr. Treasury Yield [4] | VIX [5] | Risk Premium [6] | Return on Equity [7] |
|---|---|---|---|---|
| Current 30-Year Treasury | 1.37% | 50.00 | 9.73% | 11.10% |
| Near-Term Projected 30-Year Treasury | 1.75% | 50.00 | 9.10% | 10.85% |
| Long-Term Projected 30-Year Treasury | 3.45% | 50.00 | 7.35% | 10.80% |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.877892 |
| R Square | 0.770695 |
| Adjusted R Square | 0.770166 |
| Standard Error | 0.005267 |
| Observations | 870 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 2 | 0.080823365 | 0.04041168 | 1456.993126 | 5.4887E-278 |
| Residual | 867 | 0.024047422 | 2.7736E-05 | | |
| Total | 869 | 0.104870787 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | -0.027508 | 0.001634589 | -16.828393 | 3.33048E-55 | -0.03071572 | -0.024299289 |
| LN(30-Year Treasury) | -0.02576 | 0.000480454 | -53.615831 | 1.5773E-277 | -0.02670294 | -0.024816963 |
| VIX | 0.000286 | 2.91346E-05 | 9.82722569 | 1.1091E-21 | 0.00022913 | 0.000343495 |

Notes:

[1] Constant of regression equation (1990 - 2020)
[2] Equals Regression Coefficient of 30-year Treasury Yield variable
[3] Equals Regression Coefficient of VIX variable
[4] Source: Current = Bloomberg Professional, Rebuttal Exhibit DWD-5.
Near-Term = Blue Chip Financial Forecasts, Vol. 39, No. 4, April 1, 2020, at 2
Long-Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 12, December 1, 2018, at 14
[5] Source: Testimony of J. Randall Woolridge, at 25
[6] Equals [1] + (ln([4]) x [2]) + ([3] x [5])
[7] Equals [4] + [6]
[8] Source: S&P Global Market Intelligence, Regulatory Research Associates
[9] Source: S&P Global Market Intelligence, Regulatory Research Associates
[10] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[11] Equals LN[10]
[12] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[13] Equals [9] - [10]

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 10/19/1990 | 13.00% | 8.67% | -2.45 | 22.69 | 4.33% |
| 10/25/1990 | 12.30% | 8.68% | -2.44 | 22.80 | 3.62% |
| 11/21/1990 | 12.70% | 8.69% | -2.44 | 22.98 | 4.01% |
| 12/13/1990 | 12.30% | 8.67% | -2.44 | 22.97 | 3.63% |
| 12/17/1990 | 12.87% | 8.67% | -2.45 | 23.00 | 4.20% |
| 12/18/1990 | 13.10% | 8.67% | -2.45 | 23.02 | 4.43% |
| 12/19/1990 | 12.00% | 8.66% | -2.45 | 23.04 | 3.34% |
| 12/20/1990 | 12.75% | 8.66% | -2.45 | 23.05 | 4.09% |
| 12/21/1990 | 12.50% | 8.66% | -2.45 | 23.07 | 3.84% |
| 12/27/1990 | 12.79% | 8.66% | -2.45 | 23.13 | 4.13% |
| 1/2/1991 | 13.10% | 8.66% | -2.45 | 23.25 | 4.44% |
| 1/4/1991 | 12.50% | 8.65% | -2.45 | 23.31 | 3.85% |
| 1/15/1991 | 12.75% | 8.65% | -2.45 | 23.75 | 4.10% |
| 1/25/1991 | 11.70% | 8.63% | -2.45 | 23.94 | 3.07% |
| 2/4/1991 | 12.50% | 8.60% | -2.45 | 23.92 | 3.90% |
| 2/7/1991 | 12.50% | 8.59% | -2.45 | 23.95 | 3.91% |
| 2/12/1991 | 13.00% | 8.57% | -2.46 | 23.99 | 4.43% |
| 2/14/1991 | 12.72% | 8.56% | -2.46 | 24.02 | 4.16% |
| 2/22/1991 | 12.80% | 8.55% | -2.46 | 24.08 | 4.25% |
| 3/6/1991 | 13.10% | 8.53% | -2.46 | 24.18 | 4.57% |
| 3/8/1991 | 12.30% | 8.52% | -2.46 | 24.21 | 3.78% |
| 3/8/1991 | 13.00% | 8.52% | -2.46 | 24.21 | 4.48% |
| 4/22/1991 | 13.00% | 8.49% | -2.47 | 24.23 | 4.51% |
| 5/7/1991 | 13.50% | 8.47% | -2.47 | 24.22 | 5.03% |
| 5/13/1991 | 13.25% | 8.47% | -2.47 | 24.15 | 4.78% |
| 5/30/1991 | 12.75% | 8.43% | -2.47 | 23.59 | 4.32% |
| 6/12/1991 | 12.00% | 8.41% | -2.48 | 23.03 | 3.59% |
| 6/25/1991 | 11.70% | 8.38% | -2.48 | 22.47 | 3.32% |
| 6/28/1991 | 12.50% | 8.38% | -2.48 | 22.31 | 4.12% |
| 7/1/1991 | 12.00% | 8.37% | -2.48 | 22.25 | 3.63% |
| 7/3/1991 | 12.50% | 8.36% | -2.48 | 22.15 | 4.14% |
| 7/19/1991 | 12.10% | 8.34% | -2.48 | 21.55 | 3.76% |
| 8/1/1991 | 12.90% | 8.32% | -2.49 | 20.89 | 4.58% |
| 8/16/1991 | 13.20% | 8.29% | -2.49 | 20.12 | 4.91% |
| 9/27/1991 | 12.50% | 8.23% | -2.50 | 19.02 | 4.27% |
| 9/30/1991 | 12.25% | 8.23% | -2.50 | 18.99 | 4.02% |
| 10/17/1991 | 13.00% | 8.20% | -2.50 | 18.47 | 4.80% |
| 10/23/1991 | 12.50% | 8.20% | -2.50 | 18.20 | 4.30% |
| 10/23/1991 | 12.55% | 8.20% | -2.50 | 18.20 | 4.35% |
| 10/31/1991 | 11.80% | 8.19% | -2.50 | 17.68 | 3.61% |
| 11/1/1991 | 12.00% | 8.19% | -2.50 | 17.63 | 3.81% |
| 11/5/1991 | 12.25% | 8.19% | -2.50 | 17.55 | 4.06% |
| 11/12/1991 | 12.50% | 8.18% | -2.50 | 17.35 | 4.32% |
| 11/12/1991 | 13.25% | 8.18% | -2.50 | 17.35 | 5.07% |
| 11/25/1991 | 12.40% | 8.18% | -2.50 | 17.21 | 4.22% |
| 11/26/1991 | 11.60% | 8.18% | -2.50 | 17.20 | 3.42% |
| 11/26/1991 | 12.50% | 8.18% | -2.50 | 17.20 | 4.32% |
| 11/27/1991 | 12.10% | 8.18% | -2.50 | 17.19 | 3.92% |
| 12/18/1991 | 12.25% | 8.15% | -2.51 | 17.07 | 4.10% |
| 12/19/1991 | 12.60% | 8.15% | -2.51 | 17.06 | 4.45% |
| 12/19/1991 | 12.80% | 8.15% | -2.51 | 17.06 | 4.65% |
| 12/20/1991 | 12.65% | 8.14% | -2.51 | 17.04 | 4.51% |
| 1/9/1992 | 12.80% | 8.09% | -2.51 | 17.13 | 4.71% |
| 1/16/1992 | 12.75% | 8.07% | -2.52 | 17.14 | 4.68% |
| 1/21/1992 | 12.00% | 8.06% | -2.52 | 17.12 | 3.94% |
| 1/22/1992 | 13.00% | 8.06% | -2.52 | 17.10 | 4.94% |
| 1/27/1992 | 12.65% | 8.05% | -2.52 | 17.09 | 4.60% |
| 1/31/1992 | 12.00% | 8.04% | -2.52 | 17.12 | 3.96% |
| 2/11/1992 | 12.40% | 8.03% | -2.52 | 17.16 | 4.37% |
| 2/25/1992 | 12.50% | 8.01% | -2.52 | 17.14 | 4.49% |
| 3/16/1992 | 11.43% | 7.98% | -2.53 | 17.25 | 3.45% |
| 3/18/1992 | 12.28% | 7.98% | -2.53 | 17.26 | 4.30% |
| 4/2/1992 | 12.10% | 7.95% | -2.53 | 17.24 | 4.15% |
| 4/9/1992 | 11.45% | 7.93% | -2.53 | 17.24 | 3.52% |
| 4/10/1992 | 11.50% | 7.93% | -2.53 | 17.23 | 3.57% |
| 4/14/1992 | 11.50% | 7.92% | -2.54 | 17.21 | 3.58% |
| 5/5/1992 | 11.50% | 7.89% | -2.54 | 17.08 | 3.61% |
| 5/12/1992 | 11.87% | 7.88% | -2.54 | 17.09 | 3.99% |
| 5/12/1992 | 12.46% | 7.88% | -2.54 | 17.09 | 4.58% |
| 6/1/1992 | 12.30% | 7.86% | -2.54 | 17.02 | 4.44% |
| 6/12/1992 | 10.90% | 7.85% | -2.54 | 16.97 | 3.05% |
| 6/26/1992 | 12.35% | 7.85% | -2.54 | 16.91 | 4.50% |
| 6/29/1992 | 11.00% | 7.85% | -2.55 | 16.88 | 3.15% |
| 6/30/1992 | 13.00% | 7.85% | -2.55 | 16.86 | 5.15% |
| 7/13/1992 | 11.90% | 7.84% | -2.55 | 16.78 | 4.06% |
| 7/13/1992 | 13.50% | 7.84% | -2.55 | 16.78 | 5.66% |
| 7/22/1992 | 11.20% | 7.83% | -2.55 | 16.65 | 3.37% |
| 8/3/1992 | 12.00% | 7.81% | -2.55 | 16.52 | 4.19% |
| 8/6/1992 | 12.50% | 7.80% | -2.55 | 16.48 | 4.70% |
| 9/22/1992 | 12.00% | 7.71% | -2.56 | 15.88 | 4.29% |
| 9/28/1992 | 11.40% | 7.71% | -2.56 | 15.78 | 3.69% |
| 9/30/1992 | 11.75% | 7.71% | -2.56 | 15.75 | 4.04% |
| 10/2/1992 | 13.00% | 7.70% | -2.56 | 15.74 | 5.30% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 10/12/1992 | 12.20% | 7.70% | -2.56 | 15.85 | 4.50% |
| 10/16/1992 | 13.16% | 7.71% | -2.56 | 15.82 | 5.45% |
| 10/30/1992 | 11.75% | 7.71% | -2.56 | 15.75 | 4.04% |
| 11/3/1992 | 12.00% | 7.71% | -2.56 | 15.74 | 4.29% |
| 12/3/1992 | 11.85% | 7.68% | -2.57 | 15.36 | 4.17% |
| 12/15/1992 | 11.00% | 7.66% | -2.57 | 15.17 | 3.34% |
| 12/16/1992 | 11.90% | 7.66% | -2.57 | 15.14 | 4.24% |
| 12/16/1992 | 12.40% | 7.66% | -2.57 | 15.14 | 4.74% |
| 12/17/1992 | 12.00% | 7.66% | -2.57 | 15.10 | 4.34% |
| 12/22/1992 | 12.30% | 7.65% | -2.57 | 14.99 | 4.65% |
| 12/22/1992 | 12.40% | 7.65% | -2.57 | 14.99 | 4.75% |
| 12/29/1992 | 12.25% | 7.63% | -2.57 | 14.86 | 4.62% |
| 12/30/1992 | 12.00% | 7.63% | -2.57 | 14.84 | 4.37% |
| 12/31/1992 | 11.90% | 7.62% | -2.57 | 14.82 | 4.28% |
| 1/12/1993 | 12.00% | 7.61% | -2.58 | 14.72 | 4.39% |
| 1/21/1993 | 11.25% | 7.59% | -2.58 | 14.52 | 3.66% |
| 2/2/1993 | 11.40% | 7.56% | -2.58 | 14.35 | 3.84% |
| 2/15/1993 | 12.30% | 7.52% | -2.59 | 14.26 | 4.78% |
| 2/24/1993 | 11.90% | 7.49% | -2.59 | 14.18 | 4.41% |
| 2/26/1993 | 11.80% | 7.48% | -2.59 | 14.16 | 4.32% |
| 2/26/1993 | 12.20% | 7.48% | -2.59 | 14.16 | 4.72% |
| 4/23/1993 | 11.75% | 7.29% | -2.62 | 13.85 | 4.46% |
| 5/11/1993 | 11.75% | 7.24% | -2.62 | 13.86 | 4.51% |
| 5/14/1993 | 11.50% | 7.24% | -2.63 | 13.87 | 4.26% |
| 5/25/1993 | 11.50% | 7.22% | -2.63 | 13.87 | 4.28% |
| 5/28/1993 | 11.00% | 7.22% | -2.63 | 13.84 | 3.78% |
| 6/3/1993 | 12.00% | 7.21% | -2.63 | 13.83 | 4.79% |
| 6/16/1993 | 11.50% | 7.19% | -2.63 | 13.77 | 4.31% |
| 6/18/1993 | 12.10% | 7.18% | -2.63 | 13.77 | 4.92% |
| 6/25/1993 | 11.67% | 7.17% | -2.64 | 13.74 | 4.50% |
| 7/21/1993 | 11.38% | 7.10% | -2.65 | 13.42 | 4.28% |
| 7/23/1993 | 10.46% | 7.09% | -2.65 | 13.34 | 3.37% |
| 8/24/1993 | 11.50% | 6.95% | -2.67 | 12.79 | 4.55% |
| 9/21/1993 | 10.50% | 6.80% | -2.69 | 12.72 | 3.70% |
| 9/29/1993 | 11.47% | 6.76% | -2.69 | 12.73 | 4.71% |
| 9/30/1993 | 11.60% | 6.76% | -2.69 | 12.74 | 4.84% |
| 11/2/1993 | 10.80% | 6.60% | -2.72 | 12.67 | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | -2.72 | 12.76 | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | -2.73 | 12.85 | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | -2.74 | 12.75 | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | -2.74 | 12.72 | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | -2.74 | 12.66 | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | -2.74 | 12.49 | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | -2.75 | 12.45 | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | -2.75 | 12.39 | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | -2.75 | 12.37 | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | -2.75 | 12.34 | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | -2.76 | 12.38 | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | -2.76 | 12.39 | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | -2.76 | 12.39 | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | -2.76 | 12.40 | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | -2.76 | 12.43 | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | -2.75 | 13.03 | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | -2.74 | 13.20 | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | -2.74 | 13.25 | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | -2.73 | 13.32 | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | -2.71 | 13.42 | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | -2.68 | 13.42 | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | -2.61 | 13.77 | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | -2.60 | 13.94 | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | -2.60 | 13.94 | 3.45% |
| 11/18/1994 | 11.20% | 7.46% | -2.60 | 14.12 | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | -2.59 | 14.14 | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | -2.59 | 14.20 | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | -2.58 | 14.29 | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | -2.58 | 14.29 | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | -2.58 | 14.28 | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | -2.58 | 14.26 | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | -2.58 | 14.24 | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | -2.58 | 14.14 | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | -2.57 | 14.14 | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | -2.57 | 13.71 | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | -2.56 | 13.56 | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | -2.56 | 13.49 | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | -2.56 | 13.37 | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | -2.56 | 13.35 | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | -2.56 | 13.32 | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | -2.56 | 13.31 | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | -2.56 | 13.30 | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | -2.56 | 13.28 | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | -2.56 | 13.20 | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | -2.57 | 13.21 | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | -2.57 | 13.22 | 3.55% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 6/9/1995 | 11.25% | 7.60% | -2.58 | 13.26 | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | -2.58 | 13.24 | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | -2.59 | 13.20 | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | -2.63 | 12.48 | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | -2.64 | 12.24 | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | -2.64 | 12.24 | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | -2.64 | 12.24 | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | -2.64 | 12.24 | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | -2.67 | 12.47 | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | -2.67 | 12.47 | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | -2.68 | 12.51 | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | -2.69 | 12.52 | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | -2.70 | 12.52 | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | -2.70 | 12.50 | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | -2.71 | 12.48 | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | -2.74 | 12.63 | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | -2.75 | 13.49 | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | -2.75 | 13.63 | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | -2.74 | 13.74 | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | -2.74 | 13.74 | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | -2.74 | 13.93 | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | -2.74 | 13.99 | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | -2.74 | 14.15 | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | -2.74 | 14.24 | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | -2.74 | 14.73 | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | -2.74 | 14.77 | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | -2.72 | 15.35 | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | -2.70 | 15.98 | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | -2.69 | 16.22 | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | -2.69 | 16.44 | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | -2.68 | 16.58 | 4.47% |
| 12/18/1996 | 11.75% | 6.84% | -2.68 | 16.80 | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | -2.68 | 16.84 | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | -2.68 | 16.85 | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | -2.68 | 17.23 | 4.98% |
| 2/20/1997 | 11.80% | 6.82% | -2.69 | 17.29 | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | -2.69 | 17.83 | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | -2.69 | 17.86 | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | -2.69 | 18.20 | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | -2.69 | 18.20 | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | -2.69 | 19.04 | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | -2.72 | 22.58 | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | -2.72 | 22.85 | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | -2.75 | 23.45 | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | -2.77 | 23.41 | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | -2.77 | 23.39 | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | -2.78 | 23.36 | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | -2.79 | 23.68 | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | -2.82 | 23.14 | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | -2.85 | 23.80 | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | -2.89 | 26.06 | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | -2.89 | 26.34 | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | -2.90 | 26.58 | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | -2.92 | 27.54 | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | -2.93 | 28.19 | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | -2.93 | 28.47 | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | -2.90 | 25.77 | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | -2.86 | 24.95 | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | -2.83 | 24.31 | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | -2.81 | 23.49 | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | -2.81 | 23.49 | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | -2.78 | 23.35 | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | -2.78 | 22.96 | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | -2.78 | 23.84 | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | -2.79 | 23.36 | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | -2.81 | 22.44 | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | -2.83 | 22.97 | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | -2.83 | 23.03 | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | -2.85 | 23.49 | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | -2.85 | 23.15 | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | -2.88 | 24.39 | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | -2.88 | 24.93 | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | -2.88 | 25.07 | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | -2.88 | 25.07 | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | -2.88 | 24.96 | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | -2.89 | 24.49 | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | -2.89 | 24.53 | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | -2.89 | 24.55 | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | -2.89 | 24.84 | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | -2.89 | 25.69 | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | -2.90 | 26.17 | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | -2.90 | 26.22 | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | -2.90 | 26.14 | 7.00% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 1/22/2002 | 10.00% | 5.50% | -2.90 | 25.49 | 4.50% |
| 3/27/2002 | 10.10% | 5.45% | -2.91 | 24.65 | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | -2.91 | 24.49 | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | -2.91 | 24.29 | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | -2.91 | 24.33 | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | -2.90 | 24.42 | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | -2.90 | 24.46 | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | -2.90 | 24.46 | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | -2.90 | 24.08 | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | -2.91 | 25.15 | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | -2.92 | 25.82 | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | -2.94 | 28.03 | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | -2.94 | 28.29 | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | -2.95 | 28.48 | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | -2.96 | 28.93 | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | -2.97 | 29.66 | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | -2.99 | 30.74 | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | -2.99 | 30.99 | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | -2.99 | 31.04 | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | -3.00 | 31.54 | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | -3.00 | 31.74 | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | -3.01 | 31.70 | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | -3.04 | 28.27 | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | -3.04 | 28.19 | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | -3.04 | 27.44 | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | -3.04 | 26.97 | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | -3.04 | 26.27 | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | -3.03 | 24.78 | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | -3.01 | 20.47 | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | -3.01 | 20.47 | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | -3.01 | 20.40 | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | -3.01 | 20.31 | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | -3.01 | 20.31 | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | -3.01 | 20.15 | 5.56% |
| 1/13/2004 | 12.00% | 4.95% | -3.01 | 19.31 | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | -3.00 | 18.17 | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | -2.99 | 17.96 | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | -2.99 | 17.85 | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | -2.98 | 17.43 | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | -2.98 | 17.36 | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | -2.98 | 17.33 | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | -2.98 | 17.30 | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | -2.98 | 16.96 | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | -2.98 | 16.96 | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | -2.97 | 16.69 | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | -2.98 | 16.53 | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | -2.98 | 16.35 | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | -2.98 | 15.94 | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | -2.98 | 15.75 | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | -2.98 | 15.59 | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | -2.98 | 15.51 | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | -2.98 | 15.51 | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | -2.98 | 15.47 | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | -2.98 | 15.47 | 6.43% |
| 12/29/2004 | 9.85% | 5.08% | -2.98 | 15.30 | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | -2.98 | 15.12 | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | -3.00 | 14.59 | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | -3.00 | 14.46 | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | -3.01 | 14.18 | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | -3.02 | 14.05 | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | -3.02 | 14.02 | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | -3.02 | 14.00 | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | -3.04 | 13.89 | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | -3.04 | 13.75 | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | -3.04 | 13.71 | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | -3.05 | 13.64 | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | -3.07 | 13.17 | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | -3.07 | 12.94 | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | -3.08 | 12.84 | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | -3.09 | 12.77 | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | -3.09 | 12.78 | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | -3.09 | 12.97 | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | -3.09 | 12.96 | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | -3.09 | 12.91 | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | -3.09 | 12.91 | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | -3.09 | 12.90 | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | -3.09 | 12.90 | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | -3.09 | 12.87 | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | -3.09 | 12.87 | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | -3.09 | 12.82 | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | -3.10 | 12.72 | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | -3.09 | 12.39 | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | -3.08 | 12.34 | 5.58% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 4/26/2006 | 10.60% | 4.64% | -3.07 | 12.34 | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | -3.06 | 12.47 | 6.91% |
| 6/6/2006 | 10.00% | 4.75% | -3.05 | 12.72 | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | -3.04 | 13.07 | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | -3.03 | 13.12 | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | -3.02 | 13.29 | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | -3.02 | 13.29 | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | -3.02 | 13.27 | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | -3.02 | 13.20 | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | -3.02 | 13.19 | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | -3.01 | 13.25 | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | -3.01 | 13.30 | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | -3.01 | 13.12 | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | -3.01 | 13.12 | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | -3.01 | 13.12 | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | -3.00 | 13.07 | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | -3.00 | 13.07 | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | -3.00 | 13.06 | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | -3.00 | 12.98 | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | -3.00 | 12.98 | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | -3.00 | 12.98 | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | -3.01 | 12.98 | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | -3.01 | 12.98 | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | -3.01 | 12.98 | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | -3.01 | 12.98 | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | -3.01 | 12.98 | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | -3.01 | 12.97 | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | -3.01 | 12.96 | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | -3.02 | 12.81 | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | -3.02 | 12.78 | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | -3.04 | 12.22 | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | -3.04 | 12.21 | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | -3.04 | 12.21 | 5.45% |
| 5/22/2007 | 10.20% | 4.80% | -3.04 | 12.19 | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | -3.04 | 12.19 | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | -3.04 | 12.18 | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | -3.04 | 12.16 | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | -3.03 | 12.27 | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | -3.03 | 12.30 | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | -3.03 | 12.31 | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | -3.03 | 12.38 | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | -3.02 | 12.56 | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | -3.02 | 12.65 | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | -3.02 | 12.65 | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | -3.02 | 13.76 | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | -3.01 | 15.94 | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | -3.01 | 16.15 | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | -3.02 | 16.62 | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | -3.02 | 18.14 | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | -3.02 | 18.45 | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | -3.02 | 18.60 | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | -3.02 | 18.62 | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | -3.02 | 18.62 | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | -3.02 | 18.74 | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | -3.03 | 18.77 | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | -3.03 | 18.77 | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | -3.03 | 18.84 | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | -3.03 | 18.88 | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | -3.03 | 19.16 | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | -3.03 | 19.51 | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | -3.04 | 19.99 | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | -3.04 | 20.14 | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | -3.04 | 20.21 | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | -3.05 | 21.45 | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | -3.05 | 21.99 | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | -3.06 | 22.55 | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | -3.08 | 23.32 | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | -3.08 | 23.35 | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | -3.08 | 23.46 | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | -3.09 | 23.32 | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | -3.09 | 23.18 | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | -3.09 | 22.89 | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | -3.09 | 22.73 | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | -3.09 | 22.73 | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | -3.10 | 22.88 | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | -3.10 | 23.08 | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | -3.10 | 23.33 | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | -3.10 | 23.34 | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | -3.10 | 23.37 | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | -3.10 | 23.23 | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | -3.10 | 23.01 | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | -3.11 | 23.46 | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | -3.11 | 23.46 | 6.17% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 9/24/2008 | 10.65% | 4.48% | -3.11 | 23.46 | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | -3.11 | 23.77 | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | -3.11 | 24.61 | 5.69% |
| 11/13/2008 | 10.55% | 4.45% | -3.11 | 29.58 | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | -3.11 | 29.98 | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | -3.12 | 31.79 | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | -3.15 | 34.13 | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | -3.16 | 34.34 | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | -3.16 | 34.34 | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | -3.17 | 34.47 | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | -3.18 | 35.25 | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | -3.19 | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | -3.19 | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | -3.19 | 35.81 | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | -3.20 | 36.26 | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | -3.20 | 36.58 | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | -3.20 | 36.94 | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | -3.23 | 39.59 | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | -3.24 | 40.42 | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | -3.26 | 42.04 | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | -3.27 | 42.91 | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | -3.27 | 43.10 | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | -3.28 | 43.29 | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | -3.28 | 43.40 | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | -3.29 | 43.96 | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | -3.29 | 44.24 | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | -3.28 | 45.01 | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | -3.28 | 45.06 | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | -3.28 | 44.95 | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | -3.28 | 44.55 | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | -3.27 | 38.96 | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | -3.21 | 33.90 | 6.68% |
| 10/23/2009 | 10.88% | 4.06% | -3.20 | 33.22 | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | -3.20 | 32.57 | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | -3.19 | 32.48 | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | -3.18 | 30.89 | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | -3.18 | 30.79 | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | -3.18 | 30.58 | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | -3.18 | 30.18 | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | -3.17 | 29.90 | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | -3.17 | 28.98 | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | -3.17 | 28.98 | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | -3.16 | 28.70 | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | -3.16 | 28.70 | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | -3.16 | 28.46 | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | -3.16 | 28.46 | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | -3.16 | 28.46 | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | -3.16 | 27.91 | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | -3.15 | 27.67 | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | -3.15 | 27.09 | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | -3.13 | 26.08 | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | -3.13 | 26.01 | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | -3.13 | 26.01 | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | -3.13 | 26.01 | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | -3.13 | 25.43 | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | -3.12 | 25.05 | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | -3.12 | 24.80 | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | -3.12 | 24.54 | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | -3.12 | 24.43 | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | -3.12 | 24.37 | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | -3.12 | 24.10 | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | -3.12 | 23.85 | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | -3.12 | 23.47 | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | -3.12 | 22.82 | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | -3.11 | 22.16 | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | -3.11 | 22.11 | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | -3.11 | 22.11 | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | -3.11 | 22.11 | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | -3.11 | 22.26 | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | -3.11 | 22.26 | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | -3.11 | 22.81 | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | -3.11 | 22.81 | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | -3.11 | 23.00 | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | -3.11 | 23.16 | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | -3.12 | 23.19 | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | -3.12 | 23.19 | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | -3.12 | 23.30 | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | -3.12 | 23.34 | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | -3.12 | 23.43 | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | -3.12 | 23.43 | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | -3.12 | 23.39 | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | -3.12 | 23.40 | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | -3.12 | 23.41 | 5.42% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 8/25/2010 | 9.90% | 4.37% | -3.13 | 23.38 | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | -3.14 | 23.44 | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | -3.14 | 23.46 | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | -3.14 | 23.44 | 5.68% |
| 9/16/2010 | 10.00% | 4.32% | -3.14 | 23.44 | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | -3.15 | 23.47 | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | -3.16 | 23.50 | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | -3.17 | 23.55 | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | -3.17 | 23.60 | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | -3.17 | 23.54 | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | -3.18 | 23.28 | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | -3.18 | 23.24 | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | -3.18 | 23.21 | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | -3.18 | 23.18 | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | -3.18 | 23.14 | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | -3.18 | 23.13 | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | -3.18 | 23.12 | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | -3.18 | 23.12 | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | -3.18 | 23.11 | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | -3.18 | 23.10 | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | -3.18 | 23.09 | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | -3.18 | 23.07 | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | -3.19 | 23.07 | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | -3.19 | 23.08 | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | -3.19 | 23.07 | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | -3.19 | 23.06 | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | -3.19 | 23.05 | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | -3.19 | 23.06 | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | -3.19 | 23.06 | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | -3.19 | 23.12 | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | -3.19 | 23.13 | 5.89% |
| 2/25/2011 | 10.00% | 4.14% | -3.18 | 22.58 | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | -3.18 | 21.29 | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | -3.17 | 21.16 | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | -3.17 | 20.69 | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | -3.16 | 20.17 | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | -3.16 | 20.13 | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | -3.16 | 20.08 | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | -3.16 | 19.84 | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | -3.16 | 19.84 | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | -3.15 | 19.44 | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | -3.15 | 19.02 | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | -3.14 | 18.83 | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | -3.14 | 18.83 | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | -3.13 | 18.48 | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | -3.13 | 18.46 | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | -3.13 | 18.77 | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | -3.13 | 19.05 | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | -3.13 | 19.13 | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | -3.13 | 19.53 | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | -3.14 | 20.31 | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | -3.16 | 21.34 | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | -3.19 | 22.82 | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | -3.19 | 23.27 | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | -3.25 | 25.28 | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | -3.25 | 25.28 | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | -3.27 | 25.67 | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | -3.27 | 25.67 | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | -3.28 | 25.76 | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | -3.28 | 25.76 | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | -3.28 | 25.77 | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | -3.28 | 25.77 | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | -3.29 | 25.76 | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | -3.33 | 25.89 | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | -3.34 | 25.91 | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | -3.36 | 26.12 | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | -3.37 | 26.14 | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | -3.37 | 26.15 | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | -3.38 | 26.16 | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | -3.41 | 25.99 | 7.06% |
| 4/4/2012 | 10.00% | 3.29% | -3.41 | 25.89 | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | -3.44 | 25.91 | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | -3.45 | 25.85 | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | -3.45 | 25.85 | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | -3.46 | 25.79 | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | -3.47 | 25.23 | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | -3.48 | 24.77 | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | -3.49 | 24.45 | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | -3.49 | 24.40 | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | -3.49 | 24.33 | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | -3.49 | 24.25 | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | -3.49 | 23.82 | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | -3.49 | 23.58 | 6.96% |

| [8] | [9] | [10] | [11] | [12] | [13] |
|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | LN(30-Year Treasury) | VIX | Risk Premium |
| 7/9/2012 | 10.20% | 3.03% | -3.50 | 23.14 | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | -3.50 | 22.59 | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | -3.50 | 22.07 | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | -3.50 | 22.07 | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | -3.53 | 19.11 | 6.86% |
| 9/19/2012 | 9.80% | 2.94% | -3.53 | 18.84 | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | -3.53 | 18.84 | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | -3.53 | 18.51 | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | -3.53 | 18.04 | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | -3.53 | 17.84 | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | -3.53 | 17.83 | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | -3.53 | 17.75 | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | -3.54 | 17.60 | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | -3.54 | 17.58 | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | -3.54 | 17.58 | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | -3.54 | 17.53 | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | -3.54 | 17.53 | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | -3.55 | 17.48 | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | -3.55 | 17.47 | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | -3.55 | 17.47 | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | -3.55 | 17.47 | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | -3.55 | 17.44 | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | -3.55 | 17.44 | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | -3.55 | 17.43 | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | -3.55 | 17.43 | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | -3.55 | 17.43 | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | -3.55 | 17.43 | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | -3.55 | 17.43 | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | -3.55 | 17.43 | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | -3.55 | 17.43 | 7.58% |
| 12/21/2012 | 10.20% | 2.87% | -3.55 | 17.43 | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | -3.55 | 17.45 | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | -3.56 | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | -3.56 | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | -3.56 | 17.50 | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | -3.56 | 17.45 | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | -3.56 | 17.45 | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | -3.56 | 17.01 | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | -3.56 | 16.89 | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | -3.56 | 16.85 | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | -3.55 | 16.34 | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | -3.54 | 15.87 | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | -3.53 | 15.25 | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | -3.52 | 15.02 | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | -3.51 | 14.87 | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | -3.51 | 14.89 | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | -3.51 | 14.95 | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | -3.50 | 14.99 | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | -3.50 | 15.02 | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | -3.48 | 15.06 | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | -3.46 | 14.82 | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | -3.45 | 14.72 | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | -3.42 | 14.56 | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | -3.42 | 14.56 | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | -3.41 | 14.46 | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | -3.40 | 14.45 | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | -3.38 | 14.40 | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | -3.37 | 14.36 | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | -3.37 | 14.36 | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | -3.36 | 14.38 | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | -3.36 | 14.38 | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | -3.36 | 14.38 | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | -3.36 | 14.34 | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | -3.36 | 14.34 | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | -3.35 | 14.34 | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | -3.35 | 14.35 | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | -3.35 | 14.35 | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | -3.35 | 14.35 | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | -3.35 | 14.37 | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | -3.35 | 14.37 | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | -3.35 | 14.37 | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | -3.35 | 14.37 | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | -3.35 | 14.38 | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | -3.34 | 14.41 | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | -3.30 | 14.62 | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | -3.30 | 14.65 | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | -3.29 | 14.72 | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | -3.29 | 14.66 | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | -3.29 | 14.66 | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | -3.29 | 14.58 | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | -3.30 | 14.38 | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | -3.30 | 14.35 | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | -3.30 | 14.26 | 6.73% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 6/30/2014 | 9.55% | 3.64% | -3.31 | 13.95 | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | -3.31 | 13.91 | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | -3.32 | 13.86 | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | -3.32 | 13.68 | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | -3.32 | 13.57 | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | -3.32 | 13.55 | 6.30% |
| 8/20/2014 | 9.75% | 3.56% | -3.33 | 13.61 | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | -3.34 | 13.59 | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | -3.34 | 13.57 | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | -3.35 | 13.57 | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | -3.35 | 13.57 | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | -3.37 | 13.62 | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | -3.39 | 14.09 | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | -3.39 | 14.09 | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | -3.40 | 13.94 | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | -3.40 | 13.82 | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | -3.40 | 13.82 | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | -3.41 | 13.78 | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | -3.41 | 13.80 | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | -3.41 | 13.80 | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | -3.42 | 13.83 | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | -3.42 | 13.86 | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | -3.42 | 13.96 | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | -3.42 | 13.98 | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | -3.46 | 14.37 | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | -3.49 | 14.67 | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | -3.51 | 14.90 | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | -3.52 | 14.96 | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | -3.52 | 14.98 | 6.77% |
| 4/23/2015 | 10.20% | 2.87% | -3.55 | 15.21 | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | -3.56 | 15.22 | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | -3.56 | 15.23 | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | -3.57 | 15.16 | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | -3.57 | 15.30 | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | -3.57 | 15.30 | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | -3.58 | 15.68 | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | -3.58 | 15.99 | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | -3.57 | 16.66 | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | -3.55 | 16.28 | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | -3.55 | 16.28 | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | -3.54 | 16.28 | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | -3.54 | 16.33 | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | -3.54 | 16.33 | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | -3.54 | 16.42 | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | -3.54 | 16.50 | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | -3.54 | 16.54 | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | -3.54 | 16.57 | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | -3.53 | 16.60 | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | -3.53 | 16.72 | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | -3.53 | 18.32 | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | -3.54 | 18.69 | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | -3.56 | 18.60 | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | -3.57 | 18.79 | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | -3.58 | 18.56 | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | -3.58 | 18.29 | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | -3.58 | 18.29 | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | -3.61 | 17.45 | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | -3.63 | 17.07 | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | -3.64 | 16.97 | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | -3.64 | 16.91 | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | -3.65 | 16.78 | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | -3.66 | 16.69 | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | -3.68 | 16.51 | 7.05% |
| 9/30/2016 | 9.90% | 2.53% | -3.68 | 16.46 | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | -3.70 | 15.63 | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | -3.70 | 15.60 | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | -3.69 | 15.49 | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | -3.69 | 15.34 | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | -3.69 | 14.95 | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | -3.68 | 14.87 | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | -3.68 | 14.76 | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | -3.68 | 14.76 | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | -3.68 | 14.72 | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | -3.68 | 14.62 | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | -3.68 | 14.58 | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | -3.67 | 14.50 | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | -3.67 | 14.50 | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | -3.67 | 14.40 | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | -3.67 | 14.40 | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | -3.67 | 14.34 | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | -3.66 | 14.20 | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | -3.65 | 14.12 | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | -3.65 | 14.05 | 7.50% |

| [8] Date of Electric Rate Case | [9] Return on Equity (%) | [10] 30 Year Treasury (%) | [11] LN(30-Year Treasury) | [12] VIX | [13] Risk Premium |
|---|---|---|---|---|---|
| 2/15/2017 | 9.60% | 2.62% | -3.64 | 13.89 | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | -3.64 | 13.82 | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | -3.63 | 13.79 | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | -3.63 | 13.77 | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | -3.63 | 13.74 | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | -3.62 | 13.56 | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | -3.61 | 13.28 | 7.53% |
| 4/12/2017 | 9.40% | 2.74% | -3.60 | 13.06 | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | -3.59 | 13.05 | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | -3.58 | 12.95 | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | -3.57 | 12.88 | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | -3.56 | 12.88 | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | -3.56 | 12.87 | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | -3.54 | 12.69 | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | -3.54 | 12.66 | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | -3.54 | 12.66 | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | -3.52 | 12.24 | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | -3.52 | 11.95 | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | -3.53 | 11.47 | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | -3.53 | 11.42 | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | -3.54 | 11.23 | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | -3.54 | 11.22 | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | -3.54 | 11.22 | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | -3.54 | 11.22 | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | -3.54 | 11.15 | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | -3.54 | 11.14 | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | -3.55 | 11.11 | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | -3.55 | 11.11 | 7.12% |
| 12/5/2017 | 9.50% | 2.88% | -3.55 | 11.10 | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | -3.55 | 11.10 | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | -3.55 | 11.10 | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | -3.55 | 11.09 | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | -3.55 | 11.04 | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | -3.55 | 11.04 | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | -3.56 | 11.02 | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | -3.56 | 11.00 | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | -3.56 | 10.99 | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | -3.56 | 10.96 | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | -3.56 | 10.96 | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | -3.56 | 10.84 | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | -3.56 | 10.75 | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | -3.56 | 10.76 | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | -3.56 | 11.72 | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | -3.55 | 12.08 | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | -3.55 | 12.18 | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | -3.55 | 12.69 | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | -3.54 | 13.15 | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | -3.54 | 13.18 | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | -3.54 | 13.25 | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | -3.54 | 13.25 | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | -3.54 | 13.42 | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | -3.53 | 13.84 | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | -3.53 | 13.86 | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | -3.52 | 13.86 | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | -3.52 | 13.91 | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | -3.52 | 13.91 | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | -3.52 | 14.03 | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | -3.52 | 14.06 | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | -3.51 | 14.46 | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | -3.51 | 14.58 | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | -3.50 | 14.62 | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | -3.50 | 14.67 | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | -3.50 | 14.79 | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | -3.49 | 14.81 | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | -3.49 | 14.86 | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | -3.49 | 14.86 | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | -3.49 | 14.87 | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | -3.49 | 14.93 | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | -3.47 | 15.84 | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | -3.47 | 15.94 | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | -3.47 | 15.98 | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | -3.46 | 15.93 | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | -3.46 | 16.03 | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | -3.46 | 16.04 | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | -3.46 | 16.14 | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | -3.46 | 16.20 | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | -3.46 | 16.28 | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | -3.46 | 16.66 | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | -3.47 | 16.53 | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | -3.47 | 16.60 | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | -3.47 | 16.59 | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | -3.47 | 16.59 | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | -3.47 | 16.60 | 6.53% |

| [8]<br>Date of Electric Rate Case | [9]<br>Return on Equity (%) | [10]<br>30 Year Treasury (%) | [11]<br>LN(30-Year Treasury) | [12]<br>VIX | [13]<br>Risk Premium |
|---|---|---|---|---|---|
| 4/30/2019 | 9.73% | 3.11% | -3.47 | 16.53 | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | -3.47 | 16.53 | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | -3.47 | 16.54 | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | -3.47 | 16.55 | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | -3.47 | 16.63 | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | -3.48 | 16.75 | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | -3.48 | 16.78 | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | -3.48 | 16.88 | 6.81% |
| 8/12/2019 | 9.60% | 2.89% | -3.54 | 17.13 | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | -3.57 | 17.01 | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | -3.58 | 16.98 | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | -3.61 | 16.53 | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | -3.65 | 15.55 | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | -3.65 | 15.55 | 7.40% |
| 11/1/2019 | 9.35% | 2.59% | -3.65 | 15.52 | 6.76% |
| 11/29/2019 | 9.50% | 2.52% | -3.68 | 15.10 | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | -3.69 | 15.11 | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | -3.69 | 15.11 | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | -3.70 | 15.10 | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | -3.70 | 15.08 | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | -3.70 | 15.08 | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | -3.70 | 15.04 | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | -3.70 | 15.04 | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | -3.70 | 15.04 | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | -3.70 | 15.03 | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | -3.70 | 15.03 | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | -3.71 | 15.02 | 7.04% |
| 1/8/2020 | 10.02% | 2.43% | -3.72 | 14.99 | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | -3.73 | 14.95 | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | -3.73 | 14.94 | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | -3.73 | 14.93 | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | -3.75 | 15.13 | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | -3.76 | 15.16 | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | -3.76 | 15.16 | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | -3.77 | 15.16 | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | -3.78 | 15.16 | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | -3.78 | 15.36 | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | -3.81 | 16.54 | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | -3.83 | 19.18 | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | -3.88 | 21.82 | 7.63% |
| | | | | Average: | 5.80% |
| | | | | # of Rate Cases: | 870 |

Alternative Bond Yield Plus Risk Premium Backcast

| | [14] Actual | [15] Projected | [16] Difference |
|---|---|---|---|
| 2008 | 10.37% | 10.46% | -0.09% |
| 2009 | 10.52% | 10.58% | -0.06% |
| 2010 | 10.29% | 10.35% | -0.05% |
| 2011 | 10.19% | 10.22% | -0.03% |
| 2012 | 10.01% | 9.89% | 0.12% |
| 2013 | 9.81% | 9.76% | 0.05% |
| 2014 | 9.75% | 9.79% | -0.04% |
| 2015 | 9.60% | 9.72% | -0.12% |
| 2016 | 9.60% | 9.72% | -0.12% |
| 2017 | 9.68% | 9.61% | 0.07% |
| 2018 | 9.56% | 9.69% | -0.12% |
| 2019 | 9.64% | 9.73% | -0.09% |
| 2008-2019 Average | 9.92% | 9.96% | -0.04% |

[14] Average annual authorized ROE in [9]
[15] Equals the average annual projected ROE per the regression coefficients: [1] + ([1] x [11]) + ([2] x [12]) + [10]
[16] Equals [14] - [15]

Proof Concept: Earnings, Dividends, Book Value and
Stock Price Growth Rate Equivalence in Constant Growth DCF

| Line Description | IMPLIED GROWTH RATE AT ALLOWED ROE: | | |
|---|---|---|---|
| Input | Dividend Yield | 4.00% | [1] |
| Assumes g = Allowed ROE - Div. Yield | Assumed Growth Rate | 6.50% | |
| Input | Total Return | 10.50% | [1] |
| | | | |
| Input | Payout Ratio | 65.00% | [2] |
| Input | Book Value/Share | 20 | [2] |

| | | 0 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 250 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BV/S Escalates at Constant Growth g | Book Value/Share | $ 20.00 | $ 21.30 | $ 22.68 | $ 24.16 | $ 25.73 | $ 27.40 | $ 29.18 | $ 31.08 | $ 33.10 | $ 35.25 | $ 37.54 | $ 137,540,924.55 |
| Demonstrating Constant BV/S growth | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Earnings based on ROE applied to BV/S | Earnings/share | $ 2.10 | $ 2.24 | $ 2.38 | $ 2.54 | $ 2.70 | $ 2.88 | $ 3.06 | $ 3.26 | $ 3.48 | $ 3.70 | $ 3.94 | $ 14,441,797.08 |
| Demonstrating Constant EPS growth | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| | | | | | | | | | | | | | |
| Demonstrating Constant Return Earned based on BV/S and EPS | Allowed ROE | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% | 10.50% |
| Div/S based on EPS and Constant Payout ratio | Dividends/Share | $ 1.37 | $ 1.45 | $ 1.55 | $ 1.65 | $ 1.76 | $ 1.87 | $ 1.99 | $ 2.12 | $ 2.26 | $ 2.41 | $ 2.56 | $ 9,387,168.10 |
| Demonstrating Constant Div/S growth | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Retained Earnings based on difference between EPS and Div/S | Earnings retained to book value | $ 0.74 | $ 0.78 | $ 0.83 | $ 0.89 | $ 0.95 | $ 1.01 | $ 1.07 | $ 1.14 | $ 1.22 | $ 1.30 | $ 1.38 | $ 5,054,628.98 |
| Demonstrating Constant growth in Retained Earnings | | | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% | 6.50% |
| Demonstrating Constant Market/Book ratio | Market/Book Ratio | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 | 1.817 |
| DCF calculation of market price = [Div/S]*[1+g]/[ROE-g] | Market Price | $ 36.34 | $ 38.71 | $ 41.22 | $ 43.90 | $ 46.75 | $ 49.79 | $ 53.03 | $ 56.48 | $ 60.15 | $ 64.06 | $ 68.22 | $ 249,933,350.68 |
| | | | | | | | | | | | | | |
| Demonstrating Price Appreciation equals Long Term Growth Rate | Price Appreciation | 6.50% | OK | <== Price appreciation should equal long term growth rate | | | | | | | | | |
| Demonstrating Constant Price/Earnings Ratio | Price/Earnings | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 | 17.31 |
| | | | | | | | | | | | | | |
| Present Value Factor calculated based upon the current period and the Constant ROE | Present Value Factor | | 0.9050 | 0.8190 | 0.7412 | 0.6707 | 0.6070 | 0.5493 | 0.4971 | 0.4499 | 0.4071 | 0.3684 | 0.00 |

| CASE 1 | DIVIDENDS IN PERPETUITY | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period | Present Value Dividend | 1.3156 | 1.2680 | 1.2221 | 1.1778 | 1.1352 | 1.0941 | 1.0545 | 1.0163 | 0.9795 | 0.9441 | 0.00 |
| Total Value of investment sum of all Present Value Dividends in perpetuity (250 instances for demonstration purposes) | Value of Investment | $ 36.34 | | | | | | | | | | |

| CASE 2 | 10-YEAR HOLDING PERIOD | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period | Present Value of Dividend | $ 1.32 | $ 1.27 | $ 1.22 | $ 1.18 | $ 1.14 | $ 1.09 | $ 1.05 | $ 1.02 | $ 0.98 | $ 0.94 |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value) | Present Value of Stock Price | -- | -- | -- | -- | -- | -- | -- | -- | -- | 25.14 |
| Value of dividends = sum of all Present Value Dividends for periods 1-10 | Value of Dividends | $ 11.21 | | | | | | | | | |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 10th Period (Terminal Value) | Value of Stock Price | $ 25.14 | | | | | | | | | |
| Total Value of investment sum of all Present Value Dividends for periods 1-10 and Present Value of Stock in period 10 (Terminal Value) | Value of Investment | $ 36.34 | | | | | | | | | |

| CASE 3 | 5-YEAR HOLDING PERIOD | | | | | |
|---|---|---|---|---|---|---|
| Present value of Div/S obtained by multiplying nominal Div/S by the Present Value Factor for the period | Present Value of Dividend | $ 1.32 | $ 1.27 | $ 1.22 | $ 1.18 | $ 1.14 |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value) | Present Value of Stock Price | -- | -- | -- | -- | 30.22 |
| Value of dividends = sum of all Present Value Dividends for periods 1-5 | Value of Dividends | $ 6.12 | | | | |
| Present value of Stock Price obtained by multiplying nominal Stock Price by the Present Value Factor for the 5th Period (Terminal Value) | Value of Stock Price | $ 30.22 | | | | |
| Total Value of investment sum of all Present Value Dividends for periods 1-5 and Present Value of Stock in period 5 (Terminal Value) | Value of Investment | $ 36.34 | | | | |

[1] Note, for purposes of this exhibit, these data are illustrative only.
[2] Note: Illustrative only.

Growth Rate Regression Analysis

| Company | Ticker | Median P/E | Past 10 Year Earnings Growth Rate | Past 10 Year Dividend Growth Rate | Past 10 Year Book Value Growth Rate | Past 5 Year Earnings Growth Rate | Past 5 Year Dividend Growth Rate | Past 5 Year Book Value Growth Rate | Proj. Earnings Growth Rate | Proj. Dividend Growth Rate | Proj. Book Value Growth Rate | BxR Sustainable Growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Atmos Energy Corporation | ATO | 18.00 | 7.50% | 4.00% | 6.50% | 9.50% | 6.50% | 8.50% | 7.00% | 7.50% | 7.50% | 4.50% |
| Chesapeake Utilities Corporation | CPK | 17.00 | 9.00% | 5.00% | 10.00% | 8.00% | 6.00% | 10.50% | 9.00% | 9.00% | 10.00% | 5.51% |
| Spire Inc | SR | 18.00 | 3.50% | 4.00% | 7.00% | 9.50% | 5.50% | 7.00% | 5.50% | 5.00% | 8.50% | 2.80% |
| New Jersey Resources Corporation | NJR | 17.00 | 7.00% | 7.00% | 7.00% | 6.00% | 6.50% | 8.50% | 2.50% | 6.00% | 6.50% | 3.15% |
| NiSource Inc. | NI | 20.00 | -3.00% | -2.50% | -3.50% | -7.50% | -5.50% | -6.50% | 2.50% | 7.50% | 4.00% | 5.63% |
| Northwest Natural Gas Company | NWN | 21.00 | -10.50% | 2.50% | 2.00% | -18.00% | 1.00% | - | 22.50% | 0.50% | 1.50% | 5.06% |
| ONE Gas, Inc. | OGS | NMF | - | - | - | - | - | - | 7.00% | 8.00% | 4.00% | 3.90% |
| South Jersey Industries, Inc. | SJI | 18.00 | 1.50% | 8.00% | 6.50% | -2.50% | 6.00% | 6.00% | 9.50% | 3.50% | 5.00% | 5.06% |
| Southwest Gas Corporation | SWX | 17.00 | 7.00% | 8.50% | 5.50% | 4.50% | 10.50% | 6.00% | 8.00% | 5.00% | 7.00% | 5.04% |
| UGI Corporation | UGI | 17.00 | 6.00% | 7.50% | 8.00% | 9.50% | 7.00% | 6.00% | 9.50% | 6.00% | 8.00% | 9.10% |
| ALLETE, Inc. | ALE | 18.00 | 2.50% | 3.00% | 5.00% | 4.00% | 3.50% | 5.00% | 5.50% | 5.50% | 4.50% | 2.81% |
| Alliant Energy Corporation | LNT | 17.00 | 5.00% | 7.00% | 4.00% | 5.00% | 7.00% | 5.00% | 6.50% | 5.50% | 7.50% | 3.47% |
| Ameren Corporation | AEE | 17.00 | 1.00% | -2.00% | -0.50% | 6.50% | 3.00% | 2.50% | 6.00% | 5.00% | 6.00% | 4.60% |
| American Electric Power Company, Inc. | AEP | 15.00 | 3.00% | 4.50% | 4.00% | 4.00% | 5.50% | 3.00% | 5.00% | 5.50% | 4.50% | 3.15% |
| Avangrid, Inc. | AGR | NMF | - | - | - | - | - | - | 8.50% | 3.58% | 1.50% | 1.98% |
| Avista Corporation | AVA | 17.00 | 5.50% | 8.50% | 4.00% | 5.00% | 4.50% | 4.50% | 3.50% | 3.50% | 3.50% | 2.56% |
| Black Hills Corporation | BKH | 18.00 | 6.50% | 3.00% | 2.50% | 11.00% | 4.00% | 3.00% | 5.00% | 6.50% | 5.50% | 3.80% |
| CenterPoint Energy, Inc. | CNP | 18.00 | 1.00% | 4.50% | 7.00% | -1.00% | 5.00% | 3.50% | 6.50% | 2.00% | 6.50% | 3.36% |
| CMS Energy Corporation | CMS | 18.00 | 9.50% | 15.00% | 4.50% | 7.00% | 7.00% | 5.50% | 7.50% | 7.00% | 7.50% | 5.27% |
| Consolidated Edison, Inc. | ED | 15.00 | 2.50% | 2.00% | 4.00% | 2.00% | 2.50% | 4.00% | 3.00% | 3.50% | 3.50% | 2.81% |
| Dominion Energy Inc. | D | 20.00 | 3.00% | 7.50% | 4.50% | 3.50% | 7.50% | 6.50% | 7.00% | 4.50% | 6.50% | 3.24% |
| DTE Energy Company | DTE | 17.00 | 8.00% | 5.50% | 4.50% | 7.50% | 7.00% | 5.00% | 5.00% | 6.50% | 5.50% | 3.89% |
| Duke Energy Corporation | DUK | 18.00 | 2.50% | 7.00% | 1.00% | 0.50% | 3.00% | 1.50% | 6.00% | 2.50% | 2.50% | 2.72% |
| Edison International | EIX | 13.00 | -3.50% | 6.50% | 3.00% | -9.00% | 11.00% | 3.00% | NMF | 4.50% | 5.50% | 4.51% |
| El Paso Electric Company | EE | 16.00 | 4.00% | - | 7.00% | - | 8.00% | 5.50% | 3.00% | 6.50% | 3.50% | 2.40% |
| Entergy Corporation | ETR | 13.00 | -0.50% | 2.50% | 1.00% | 0.50% | 1.50% | -2.50% | 3.00% | 4.00% | 5.00% | 3.85% |
| Evergy, Inc. | EVRG | NMF | - | - | - | - | - | - | NMF | NMF | NMF | 2.72% |
| Exelon Corporation | EXC | 14.00 | -5.50% | -3.50% | 7.00% | -3.50% | -7.00% | 4.50% | 8.00% | 5.50% | 5.00% | 4.68% |
| FirstEnergy Corp. | FE | 17.00 | -7.00% | -2.50% | -8.00% | -2.50% | -5.00% | -17.50% | 7.00% | 3.00% | 8.50% | 6.00% |
| Hawaiian Electric Industries, Inc. | HE | 18.00 | 5.00% | - | 3.00% | 4.00% | - | 3.50% | 2.50% | 3.00% | 3.50% | 2.88% |
| IDACORP, Inc. | IDA | 14.00 | 7.00% | 6.50% | 5.50% | 4.00% | 10.00% | 5.00% | 3.50% | 7.00% | 4.00% | 3.52% |
| MGE Energy, Inc. | MGEE | 20.00 | 4.50% | 3.50% | 5.50% | 2.50% | 4.00% | 5.50% | 5.50% | 5.50% | 5.00% | 4.83% |
| NextEra Energy, Inc. | NEE | 16.00 | 6.00% | 9.00% | 8.50% | 6.00% | 10.50% | 9.50% | 10.00% | 10.50% | 7.00% | 4.68% |
| Eversource Energy | ES | 18.00 | 8.00% | 9.50% | 6.50% | 7.00% | 8.00% | 5.00% | 5.50% | 6.00% | 5.00% | 3.61% |
| NorthWestern Corporation | NWE | 16.00 | 8.50% | 5.00% | 5.50% | 7.00% | 7.00% | 8.00% | 2.00% | 4.50% | 3.50% | 2.79% |
| OGE Energy Corp. | OGE | 17.00 | 5.00% | 7.00% | 7.00% | 2.00% | 10.00% | 5.50% | 4.50% | 6.00% | 3.50% | 3.08% |
| Otter Tail Corporation | OTTR | 22.00 | 5.50% | 1.50% | - | 9.00% | 2.50% | 4.50% | 5.00% | 5.00% | 5.00% | 4.03% |
| Pinnacle West Capital Corporation | PNW | 15.00 | 4.50% | 2.50% | 2.50% | 5.00% | 3.00% | 4.50% | 4.00% | 6.00% | 3.50% | 3.20% |
| PNM Resources, Inc. | PNM | 18.00 | 7.00% | 2.50% | - | 6.00% | 11.00% | 1.00% | 7.00% | 7.00% | 5.00% | 3.78% |
| Portland General Electric Company | POR | 16.00 | 3.50% | 4.50% | 2.50% | 4.00% | 4.50% | 3.50% | 4.50% | 6.50% | 3.00% | 3.06% |
| PPL Corporation | PPL | 13.00 | - | 2.50% | 1.00% | -0.50% | 2.00% | -4.00% | 2.50% | 2.00% | 6.00% | 5.67% |
| Public Service Enterprise Group Incorporated | PEG | 13.00 | 1.50% | 3.50% | 6.50% | 1.00% | 4.00% | 5.00% | 6.00% | 5.00% | 5.00% | 4.84% |
| Sempra Energy | SRE | 19.00 | 1.00% | 10.00% | 5.50% | 2.00% | 7.50% | 4.00% | 11.00% | 8.00% | 7.00% | 4.83% |
| Southern Company | SO | 16.00 | 3.00% | 3.50% | 4.00% | 2.50% | 3.50% | 3.00% | 4.00% | 3.00% | 4.00% | 3.77% |
| WEC Energy Group, Inc. | WEC | 18.00 | 8.50% | 14.50% | 8.00% | 6.00% | 9.50% | 10.50% | 6.00% | 6.50% | 3.50% | 4.00% |
| Xcel Energy Inc. | XEL | 15.00 | 5.50% | 4.50% | 4.50% | 5.00% | 6.00% | 4.50% | 5.50% | 6.00% | 5.50% | 3.78% |

Notes:
Source: Value Line Reports as of April 17, 2020

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.38418 |
| R Square | 0.14760 |
| Adjusted R Square | 0.12629 |
| Standard Error | 1.90880 |
| Observations | 42 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 25.23570 | 25.23570 | 6.92620 | 0.01201 |
| Residual | 40 | 145.74049 | 3.64351 | | |
| Total | 41 | 170.97619 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 15.65068 | 0.59915 | 26.12165 | 0.00000 | 14.43976 | 16.86160 |
| Project Earnings Growth Rate | 22.84020 | 8.67865 | 2.63177 | 0.01201 | 5.29999 | 40.38041 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.00547 |
| R Square | 0.00003 |
| Adjusted R Square | -0.02436 |
| Standard Error | 2.13442 |
| Observations | 43 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 0.00558 | 0.00558 | 0.00122 | 0.97225 |
| Residual | 41 | 186.78512 | 4.55573 | | |
| Total | 42 | 186.79070 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.89876 | 0.95654 | 17.66646 | 0.00000 | 14.96698 | 18.83054 |
| Proj. Dividend Growth Rate | 0.59232 | 16.92641 | 0.03499 | 0.97225 | -33.59125 | 34.77589 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.024240794 |
| R Square | 0.000587616 |
| Adjusted R Square | -0.023788296 |
| Standard Error | 2.133821354 |
| Observations | 43 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 0.10976122 | 0.10976122 | 0.024106425 | 0.877376303 |
| Residual | 41 | 186.6809365 | 4.553193572 | | |
| Total | 42 | 186.7906977 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.7812709 | 1.013100223 | 16.5642752 | 9.07295E-20 | 14.73527349 | 18.82726831 |
| Proj. Book Value Growth Rate | 2.809364548 | 18.09429609 | 0.155262439 | 0.877376303 | -33.73280775 | 39.35153684 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.02706 |
| R Square | 0.00073 |
| Adjusted R Square | -0.02425 |
| Standard Error | 2.06671 |
| Observations | 42 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.12522 | 0.12522 | 0.02932 | 0.86491 |
| Residual | 40 | 170.85097 | 4.27127 | | |
| Total | 41 | 170.97619 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.97897 | 0.41265 | 41.14633 | 0.00000 | 16.14498 | 17.81296 |
| Past 10 Year Earnings Growth Rate | 1.25972 | 7.35720 | 0.17122 | 0.86491 | -13.60973 | 16.12917 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.10269 |
| R Square | 0.01055 |
| Adjusted R Square | -0.01483 |
| Standard Error | 2.16518 |
| Observations | 41 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1.94861 | 1.94861 | 0.41566 | 0.52288 |
| Residual | 39 | 182.83187 | 4.68800 | | |
| Total | 40 | 184.78049 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.65041 | 0.54605 | 30.49253 | 0.00000 | 15.54592 | 17.75489 |
| Past 10 Year Dividend Growth Rate | 5.59672 | 8.68089 | 0.64472 | 0.52288 | -11.96204 | 23.15549 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.02129 |
| R Square | 0.00045 |
| Adjusted R Square | -0.02518 |
| Standard Error | 2.01884 |
| Observations | 41 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 0.07205 | 0.07205 | 0.01768 | 0.89491 |
| Residual | 39 | 158.95234 | 4.07570 | | |
| Total | 40 | 159.02439 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.83684 | 0.52824 | 31.87335 | 0.00000 | 15.76837 | 17.90531 |
| Past 10 Year Book Value Growth Rate | -1.28712 | 9.68080 | -0.13296 | 0.89491 | -20.86839 | 18.29415 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.03917 |
| R Square | 0.00153 |
| Adjusted R Square | -0.02343 |
| Standard Error | 2.15418 |
| Observations | 42 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 0.28526 | 0.28526 | 0.06147 | 0.80545 |
| Residual | 40 | 185.61951 | 4.64049 | | |
| Total | 41 | 185.90476 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.90466 | 0.38411 | 44.01028 | 0.00000 | 16.12835 | 17.68097 |
| Past 5 Year Earnings Growth Rate | 1.51848 | 6.12452 | 0.24793 | 0.80545 | -10.85964 | 13.89659 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.03246 |
| R Square | 0.00105 |
| Adjusted R Square | -0.02392 |
| Standard Error | 2.15304 |
| Observations | 42 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 0.19554 | 0.19554 | 0.04218 | 0.83832 |
| Residual | 40 | 185.42351 | 4.63559 | | |
| Total | 41 | 185.61905 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.99106 | 0.53567 | 31.71933 | 0.00000 | 15.90844 | 18.07369 |
| Past 5 Year Dividend Growth Rate | -1.68983 | 8.22774 | -0.20538 | 0.83832 | -18.31872 | 14.93906 |

SUMMARY OUTPUT

| Regression Statistics | |
|---|---|
| Multiple R | 0.098261747 |
| R Square | 0.009655371 |
| Adjusted R Square | -0.015103245 |
| Standard Error | 2.050570223 |
| Observations | 42 |

ANOVA

| | df | SS | MS | F | Significance F |
|---|---|---|---|---|---|
| Regression | 1 | 1.639803818 | 1.639803818 | 0.389980238 | 0.535855746 |
| Residual | 40 | 168.1935295 | 4.204838238 | | |
| Total | 41 | 169.8333333 | | | |

| | Coefficients | Standard Error | t Stat | P-value | Lower 95% | Upper 95% |
|---|---|---|---|---|---|---|
| Intercept | 16.6655746 | 0.415066707 | 40.15155718 | 6.07414E-34 | 15.8266935 | 17.50445571 |
| Past 5 Year Book Value Growth Rate | 4.231751789 | 6.776397699 | 0.624483978 | 0.535855746 | -9.463858835 | 17.92736241 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.116023492 |
| R Square | 0.013461451 |
| Adjusted R Square | -0.010600465 |
| Standard Error | 2.083827353 |
| Observations | 43 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 2.42932228 | 2.42932228 | 0.559450497 | 0.458750721 |
| Residual | 41 | 178.035794 | 4.342336439 | | |
| Total | 42 | 180.4651163 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 17.54125733 | 1.322059625 | 13.26812875 | 1.99027E-16 | 14.87130375 | 20.2112109 |
| BxR Sustainable Growth | -24.16089973 | 32.30221258 | -0.747964235 | 0.458750721 | -89.39654147 | 41.07474201 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.748562859 |
| R Square | 0.560346353 |
| Adjusted R Square | 0.384484895 |
| Standard Error | 1.332008527 |
| Observations | 36 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 10 | 56.53272099 | 5.653272099 | 3.186294244 | 0.009062744 |
| Residual | 25 | 44.3561679 | 1.774246716 | | |
| Total | 35 | 100.8888889 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 16.98268641 | 1.065469549 | 15.93915699 | 1.31988E-14 | 14.7883108 | 19.17706202 |
| Past 10 YearEarningsGrowth Rate | 8.159157225 | 17.84182259 | 0.457305143 | 0.651401031 | -28.58676425 | 44.9050787 |
| Past 10 YearDividendGrowth Rate | 6.854393677 | 8.036053791 | 0.852955176 | 0.401782509 | -9.696168918 | 23.40495627 |
| Past 10 YearBook ValueGrowth Rate | -20.07636098 | 23.02960726 | -0.871763064 | 0.391633055 | -67.50672499 | 27.35400302 |
| Past 5 YearEarningsGrowth Rate | 16.82718561 | 11.91068235 | 1.41278099 | 0.170049431 | -7.703323881 | 41.35769509 |
| Past 5 YearDividendGrowth Rate | -1.506977664 | 10.56977991 | -0.142574176 | 0.887769352 | -23.27584688 | 20.26189156 |
| Past 5 YearBook ValueGrowth Rate | -0.226215047 | 19.05041108 | -0.011874549 | 0.990619958 | -39.46127111 | 39.00884102 |
| Proj.EarningsGrowth Rate | 69.52486402 | 16.69329139 | 4.16483858 | 0.00032412 | 35.14438683 | 103.9053412 |
| Proj.DividendGrowth Rate | -20.66089038 | 17.0184553 | -1.214028536 | 0.236081248 | -55.71105517 | 14.38927441 |
| Proj. Book Value Growth Rate | -12.58594719 | 15.49360334 | -0.812331832 | 0.424269388 | -44.49562059 | 19.32372621 |
| BxR Sustainable Growth | -84.21749433 | 31.63689195 | -2.66200278 | 0.013382066 | -149.374893 | -19.06009567 |

Bond Yield Plus Risk Premium - Settled Cases

| | [1] Constant | [2] Slope | [3] 30-Year Treasury Yield | [4] Risk Premium | [5] Return on Equity |
|---|---|---|---|---|---|
| Current | -1.63% | -2.40% | 1.37% | 8.67% | 10.04% |
| Near-Term Projected | -1.63% | -2.40% | 1.75% | 8.08% | 9.83% |
| Long-Term Projected | -1.63% | -2.40% | 3.45% | 6.45% | 9.90% |

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Rebuttal Exhibit DWD-5
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]

Bond Yield Plus Risk Premium - Fully Litigated Cases

| | [1] Constant | [2] Slope | [3] 30-Year Treasury Yield | [4] Risk Premium | [5] Return on Equity |
|---|---|---|---|---|---|
| Current | -2.64% | -2.74% | 1.37% | 9.12% | 10.49% |
| Near Term Projected | -2.64% | -2.74% | 1.75% | 8.45% | 10.20% |
| Long-Term Projected | -2.64% | -2.74% | 3.45% | 6.59% | 10.04% |

Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Rebuttal Exhibit DWD-5
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]

| | Litigated | Settled | Difference |
|---|---|---|---|
| Authorized ROEs January 2015 - April 17, 2020 | 9.54% | 9.66% | 0.13% |

Source: Regulatory Research Associates

Implied Return on Equity with M/B Ratio at Unity

| Institution Name | Ticker | ROACE (%) 2019Y | Price/ Book (%) 2019Y |
|---|---|---|---|
| ALLETE, Inc. | ALE | 8.43 | 187.9 |
| Alliant Energy Corporation | LNT | 11.58 | 257.6 |
| Ameren Corporation | AEE | 10.55 | 234.6 |
| American Electric Power Company, Inc. | AEP | 9.92 | 237.9 |
| Atmos Energy Corporation | ATO | 9.39 | 236.4 |
| Avangrid, Inc. | AGR | 4.62 | 103.8 |
| Avista Corporation | AVA | 10.50 | 166.6 |
| Black Hills Corporation | BKH | 8.67 | 204.4 |
| CenterPoint Energy, Inc. | CNP | 10.34 | 206.9 |
| Chesapeake Utilities Corporation | CPK | 11.99 | 278.3 |
| CMS Energy Corporation | CMS | 13.91 | 355.5 |
| Consolidated Edison, Inc. | ED | 7.63 | 167.2 |
| Dominion Energy, Inc. | D | 5.15 | 234.4 |
| DTE Energy Company | DTE | 10.97 | 213.9 |
| Duke Energy Corporation | DUK | 8.37 | 149.1 |
| Edison International | EIX | 11.10 | 205.2 |
| El Paso Electric Company | EE | 10.33 | 227.3 |
| Entergy Corporation | ETR | 12.95 | 233.4 |
| Evergy, Inc. | EVRG | 7.40 | 172.1 |
| Eversource Energy | ES | 7.61 | 222.2 |
| Exelon Corporation | EXC | 9.29 | 137.7 |
| FirstEnergy Corp. | FE | 12.84 | 376.7 |
| Hawaiian Electric Industries, Inc. | HE | 9.84 | 223.9 |
| IDACORP, Inc. | IDA | 9.64 | 218.4 |
| MGE Energy, Inc. | MGEE | 10.38 | 319.3 |
| New Jersey Resources Corporation | NJR | 11.07 | 262.3 |
| NextEra Energy, Inc. | NEE | 10.67 | 320.0 |
| NiSource Inc. | NI | 6.58 | 208.3 |
| Northwest Natural Holding Company | NWN | 7.42 | 259.4 |
| NorthWestern Corporation | NWE | 10.11 | 177.3 |
| OGE Energy Corp. | OGE | 10.68 | 215.0 |
| ONE Gas, Inc. | OGS | 8.89 | 231.9 |
| Otter Tail Corporation | OTTR | 11.59 | 263.6 |
| Pinnacle West Capital Corporation | PNW | 10.08 | 186.2 |
| PNM Resources, Inc. | PNM | 4.65 | 240.6 |
| Portland General Electric Company | POR | 8.39 | 192.5 |
| PPL Corporation | PPL | 14.43 | 211.9 |
| Public Service Enterprise Group Incorporated | PEG | 11.43 | 197.2 |
| Sempra Energy | SRE | 13.07 | 250.1 |
| South Jersey Industries, Inc. | SJI | 5.35 | 214.0 |
| Southern Company | SO | 17.72 | 243.9 |
| Southwest Gas Holdings, Inc. | SWX | 8.94 | 166.8 |
| Spire Inc. | SR | 7.66 | 193.3 |
| UGI Corporation | UGI | 6.79 | 275.2 |
| WEC Energy Group, Inc. | WEC | 11.34 | 287.7 |
| Xcel Energy Inc. | XEL | 10.85 | 251.6 |

Source: S&P Global Market Intelligence

Implied Return on Equity with M/B Ratio at Unity

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.419390367 |
| R Square | 0.17588828 |
| Adjusted R Square | 0.157158468 |
| Standard Error | 48.54620381 |
| Observations | 46 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 22131.66238 | 22131.66238 | 9.39081936 | 0.003716974 |
| Residual | 44 | 103696.2918 | 2356.733905 | | |
| Total | 45 | 125827.9542 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 143.0499577 | 28.15860109 | 5.080151435 | 7.39609E-06 | 86.30002615 | 199.7998893 |
| ROACE | 8.510111287 | 2.777048702 | 3.06444438 | 0.003716974 | 2.913337381 | 14.10688519 |

| ROE (%) | PRICE/BOOK |
|---|---|
| -5.06 | 100.00 |
| -3.88 | 110.00 |

Constant Growth Discounted Cash Flow Model and Credit Ratings
30 Day Dividend Yield

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | Dividend Yield | Expected Dividend Yield | Yahoo Earnings Growth | Zacks Earnings Growth | Average Earnings Growth | Mean ROE | S&P Issuer Credit Rating | Numeric Credit Score |
| ALLETE, Inc. | ALE | 3.00% | 3.11% | 7.00% | 7.20% | 7.10% | 10.21% | BBB+ | 5 |
| Alliant Energy Corporation | LNT | 2.68% | 2.75% | 5.40% | 5.49% | 5.45% | 8.20% | A- | 4 |
| Ameren Corporation | AEE | 2.50% | 2.57% | 6.05% | 5.65% | 5.85% | 8.42% | BBB+ | 5 |
| American Electric Power Company, Inc. | AEP | 2.85% | 2.92% | 4.60% | 6.24% | 5.42% | 8.34% | A- | 4 |
| Avangrid, Inc. | AGR | 3.40% | 3.46% | 3.50% | 3.36% | 3.43% | 6.89% | BBB+ | 5 |
| Avista Corporation | AVA | 3.30% | 3.42% | 6.20% | 7.39% | 6.80% | 10.21% | BBB | 6 |
| CMS Energy Corporation | CMS | 2.50% | 2.58% | 7.50% | 6.42% | 6.96% | 9.54% | BBB+ | 5 |
| Consolidated Edison, Inc. | ED | 3.37% | 3.40% | 2.37% | 2.00% | 2.19% | 5.59% | A- [7] | 4 |
| Dominion Energy, Inc. | D | 4.50% | 4.60% | 4.41% | 4.78% | 4.60% | 9.20% | BBB+ | 5 |
| Duke Energy Corporation | DUK | 4.03% | 4.12% | 4.40% | 4.84% | 4.62% | 8.74% | A- | 4 |
| Edison International | EIX | 3.34% | 3.42% | 3.90% | 5.42% | 4.66% | 8.08% | BBB | 6 |
| Entergy Corporation | ETR | 2.96% | 3.01% | -1.50% | 7.00% | 2.75% | 5.76% | BBB+ | 5 |
| Evergy, Inc. | EVRG | 2.98% | 3.08% | 6.70% | 6.57% | 6.64% | 9.71% | A- | 4 |
| Eversource Energy | ES | 2.58% | 2.65% | 5.45% | 5.63% | 5.54% | 8.19% | A- | 4 |
| Exelon Corporation | EXC | 3.26% | 3.30% | 0.46% | 4.19% | 2.33% | 5.62% | BBB+ | 5 |
| FirstEnergy Corp. | FE | 3.16% | 3.15% | -6.60% | 6.00% | -0.30% | 2.85% | BBB | 6 |
| Hawaiian Electric Industries, Inc. | HE | 2.70% | 2.75% | 3.40% | 4.22% | 3.81% | 6.56% | BBB- | 7 |
| IDACORP, Inc. | IDA | 2.46% | 2.50% | 2.50% | 3.85% | 3.18% | 5.68% | BBB | 6 |
| MGE Energy, Inc. | MGEE | 1.79% | 1.82% | 4.00% | N/A | 4.00% | 5.82% | AA- | 1 |
| NextEra Energy, Inc. | NEE | 1.96% | 2.04% | 7.99% | 7.98% | 7.99% | 10.03% | A- | 4 |
| NorthWestern Corporation | NWE | 3.11% | 3.15% | 3.23% | 2.75% | 2.99% | 6.14% | BBB | 6 |
| OGE Energy Corp. | OGE | 3.43% | 3.50% | 3.50% | 4.26% | 3.88% | 7.38% | BBB+ | 5 |
| Otter Tail Corporation | OTTR | 2.80% | 2.91% | 9.00% | 7.00% | 8.00% | 10.91% | BBB | 6 |
| Pinnacle West Capital Corporation | PNW | 3.34% | 3.42% | 4.11% | 4.91% | 4.51% | 7.93% | A- | 4 |
| PNM Resources, Inc. | PNM | 2.37% | 2.44% | 6.25% | 5.40% | 5.83% | 8.26% | BBB+ | 5 |
| Portland General Electric Company | POR | 2.64% | 2.70% | 4.80% | 4.78% | 4.79% | 7.49% | BBB+ | 5 |
| PPL Corporation | PPL | 4.59% | 4.60% | 0.50% | N/A | 0.50% | 5.10% | A- | 4 |
| Sempra Energy | SRE | 2.49% | 2.60% | 10.05% | 7.73% | 8.89% | 11.49% | BBB+ | 5 |
| Southern Company | SO | 3.72% | 3.78% | 1.53% | 4.50% | 3.02% | 6.79% | A- | 4 |
| WEC Energy Group, Inc. | WEC | 2.64% | 2.72% | 6.05% | 6.14% | 6.10% | 8.81% | A- | 4 |
| Xcel Energy Inc. | XEL | 2.47% | 2.54% | 6.10% | 5.42% | 5.76% | 8.30% | A- | 4 |
| PROXY GROUP MEAN | | 3.00% | 3.07% | 4.29% | 5.42% | 4.75% | 7.81% | BBB+ | 4.74 |
| PROXY GROUP MEDIAN | | 2.96% | 3.01% | 4.41% | 5.42% | 4.66% | 8.19% | BBB+ | 5.00 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.007937496 |
| R Square | 6.30038E-05 |
| Adjusted R Square | -0.034417582 |
| Standard Error | 0.01968308 |
| Observations | 31 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 7.07911E-07 | 7.0791E-07 | 0.0018272 | 0.96619692 |
| Residual | 29 | 0.011235286 | 0.00038742 | | |
| Total | 30 | 0.011235994 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.077483509 | 0.015966233 | 4.85296127 | 3.817E-05 | 0.0448289 | 0.1101381 |
| Credit Score | 0.000140355 | 0.003283457 | 0.04274607 | 0.9661969 | -0.00657507 | 0.0068558 |

Notes:
[1] Source: Exhibit JRW-7
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: Exhibit JRW-7
[4] Source: Exhibit JRW-7
[5] Equals Average([3], [4])
[6] Equals [2] + [5]
[7] Source: Exhibit JRW-2. Note: Exh. JRW-2 incorrectly denotes ED as being rated BBB+
[8] AA- = 1; A+ = 2; A = 3; A- = 4; BBB+ = 5; BBB = 6; BBB- = 7

Constant Growth Discounted Cash Flow Model and Credit Ratings
90 Day Dividend Yield

| | | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] |
|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | Dividend Yield | Expected | Yahoo | Zacks | Average | Mean | S&P | Numeric |
| ALLETE, Inc. | ALE | 3.00% | 3.10% | 7.00% | 7.20% | 7.10% | 10.20% | BBB+ | 5 |
| Alliant Energy Corporation | LNT | 2.80% | 2.88% | 5.40% | 5.49% | 5.45% | 8.32% | A- | 4 |
| Ameren Corporation | AEE | 2.58% | 2.65% | 6.05% | 5.65% | 5.85% | 8.50% | BBB+ | 5 |
| American Electric Power Company, Inc. | AEP | 2.97% | 3.05% | 4.60% | 6.24% | 5.42% | 8.47% | A- | 4 |
| Avangrid, Inc. | AGR | 3.50% | 3.56% | 3.50% | 3.36% | 3.43% | 6.99% | BBB+ | 5 |
| Avista Corporation | AVA | 3.37% | 3.48% | 6.20% | 7.39% | 6.80% | 10.28% | BBB | 6 |
| CMS Energy Corporation | CMS | 2.58% | 2.67% | 7.50% | 6.42% | 6.96% | 9.63% | BBB+ | 5 |
| Consolidated Edison, Inc. | ED | 3.41% | 3.45% | 2.37% | 2.00% | 2.19% | 5.63% | A- [7] | 4 |
| Dominion Energy, Inc. | D | 4.56% | 4.67% | 4.41% | 4.78% | 4.60% | 9.26% | BBB+ | 5 |
| Duke Energy Corporation | DUK | 4.10% | 4.20% | 4.40% | 4.84% | 4.62% | 8.82% | A- | 4 |
| Edison International | EIX | 3.52% | 3.61% | 3.90% | 5.42% | 4.66% | 8.27% | BBB | 6 |
| Entergy Corporation | ETR | 3.09% | 3.13% | -1.50% | 7.00% | 2.75% | 5.88% | BBB+ | 5 |
| Evergy, Inc. | EVRG | 3.11% | 3.21% | 6.70% | 6.57% | 6.64% | 9.84% | A- | 4 |
| Eversource Energy | ES | 2.68% | 2.76% | 5.45% | 5.63% | 5.54% | 8.30% | A- | 4 |
| Exelon Corporation | EXC | 3.34% | 3.38% | 0.46% | 4.19% | 2.33% | 5.71% | BBB+ | 5 |
| FirstEnergy Corp. | FE | 3.23% | 3.22% | -6.60% | 6.00% | -0.30% | 2.92% | BBB | 6 |
| Hawaiian Electric Industries, Inc. | HE | 2.81% | 2.86% | 3.40% | 4.22% | 3.81% | 6.67% | BBB- | 7 |
| IDACORP, Inc. | IDA | 2.50% | 2.54% | 2.50% | 3.85% | 3.18% | 5.71% | BBB | 6 |
| MGE Energy, Inc. | MGEE | 1.82% | 1.85% | 4.00% | N/A | 4.00% | 5.85% | AA- | 1 |
| NextEra Energy, Inc. | NEE | 2.08% | 2.16% | 7.99% | 7.98% | 7.99% | 10.15% | A- | 4 |
| NorthWestern Corporation | NWE | 3.17% | 3.21% | 3.23% | 2.75% | 2.99% | 6.20% | BBB | 6 |
| OGE Energy Corp. | OGE | 3.54% | 3.61% | 3.50% | 4.26% | 3.88% | 7.49% | BBB+ | 5 |
| Otter Tail Corporation | OTTR | 2.84% | 2.95% | 9.00% | 7.00% | 8.00% | 10.95% | BBB | 6 |
| Pinnacle West Capital Corporation | PNW | 3.44% | 3.51% | 4.11% | 4.91% | 4.51% | 8.02% | A- | 4 |
| PNM Resources, Inc. | PNM | 2.43% | 2.50% | 6.25% | 5.40% | 5.83% | 8.32% | BBB+ | 5 |
| Portland General Electric Company | POR | 2.72% | 2.78% | 4.80% | 4.78% | 4.79% | 7.57% | BBB+ | 5 |
| PPL Corporation | PPL | 4.79% | 4.80% | 0.50% | N/A | 0.50% | 5.30% | A- | 4 |
| Sempra Energy | SRE | 2.59% | 2.70% | 10.05% | 7.73% | 8.89% | 11.59% | BBB+ | 5 |
| Southern Company | SO | 3.90% | 3.96% | 1.53% | 4.50% | 3.02% | 6.98% | A- | 4 |
| WEC Energy Group, Inc. | WEC | 2.73% | 2.82% | 6.05% | 6.14% | 6.10% | 8.91% | A- | 4 |
| Xcel Energy Inc. | XEL | 2.55% | 2.63% | 6.10% | 5.42% | 5.76% | 8.39% | A- | 4 |
| PROXY GROUP MEAN | | 3.09% | 3.16% | 4.29% | 5.42% | 4.75% | 7.91% | BBB+ | 4.74 |
| PROXY GROUP MEDIAN | | 3.00% | 3.10% | 4.41% | 5.42% | 4.66% | 8.30% | BBB+ | 5.00 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.006262744 |
| R Square | 3.9222E-05 |
| Adjusted R Square | -0.034442184 |
| Standard Error | 0.019641716 |
| Observations | 31 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 4.38837E-07 | 4.3884E-07 | 0.0011375 | 0.97332626 |
| Residual | 29 | 0.011188114 | 0.0003858 | | |
| Total | 30 | 0.011188552 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.078554934 | 0.01593268 | 4.9304282 | 3.078E-05 | 0.04596894 | 0.1111409 |
| Credit Score | 0.000110507 | 0.003276557 | 0.03372657 | 0.9733263 | -0.0065908 | 0.0068118 |

Notes:
[1] Source: Exhibit JRW-7
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: Exhibit JRW-7
[4] Source: Exhibit JRW-7
[5] Equals Average([3], [4])
[6] Equals [2] + [5]
[7] Source: Exhibit JRW-2. Note: Exh. JRW-2 incorrectly denotes ED as being rated BBB+
[8] AA- = 1; A+ = 2; A = 3; A- = 4; BBB+ = 5; BBB = 6; BBB- = 7

Constant Growth Discounted Cash Flow Model and Credit Ratings
180 Day Dividend Yield

| Company | Ticker | [1] Dividend Yield | [2] Expected | [3] Yahoo | [4] Zacks | [5] Average | [6] Mean | [7] S&P | [8] Numeric |
|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 2.94% | 3.04% | 7.00% | 7.20% | 7.10% | 10.14% | BBB+ | 5 |
| Alliant Energy Corporation | LNT | 2.89% | 2.97% | 5.40% | 5.49% | 5.45% | 8.41% | A- | 4 |
| Ameren Corporation | AEE | 2.58% | 2.65% | 6.05% | 5.65% | 5.85% | 8.50% | BBB+ | 5 |
| American Electric Power Company, Inc. | AEP | 3.03% | 3.11% | 4.60% | 6.24% | 5.42% | 8.53% | A- | 4 |
| Avangrid, Inc. | AGR | 3.49% | 3.55% | 3.50% | 3.36% | 3.43% | 6.98% | BBB+ | 5 |
| Avista Corporation | AVA | 3.45% | 3.56% | 6.20% | 7.39% | 6.80% | 10.36% | BBB | 6 |
| CMS Energy Corporation | CMS | 2.64% | 2.73% | 7.50% | 6.42% | 6.96% | 9.69% | BBB+ | 5 |
| Consolidated Edison, Inc. | ED | 3.43% | 3.46% | 2.37% | 2.00% | 2.19% | 5.65% | A- [7] | 4 |
| Dominion Energy, Inc. | D | 4.71% | 4.82% | 4.41% | 4.78% | 4.60% | 9.41% | BBB+ | 5 |
| Duke Energy Corporation | DUK | 4.14% | 4.23% | 4.40% | 4.84% | 4.62% | 8.86% | A- | 4 |
| Edison International | EIX | 3.58% | 3.67% | 3.90% | 5.42% | 4.66% | 8.33% | BBB | 6 |
| Entergy Corporation | ETR | 3.26% | 3.30% | -1.50% | 7.00% | 2.75% | 6.05% | BBB+ | 5 |
| Evergy, Inc. | EVRG | 3.16% | 3.27% | 6.70% | 6.57% | 6.64% | 9.90% | A- | 4 |
| Eversource Energy | ES | 2.77% | 2.85% | 5.45% | 5.63% | 5.54% | 8.39% | A- | 4 |
| Exelon Corporation | EXC | 3.27% | 3.31% | 0.46% | 4.19% | 2.33% | 5.64% | BBB+ | 5 |
| FirstEnergy Corp. | FE | 3.35% | 3.34% | -6.60% | 6.00% | -0.30% | 3.04% | BBB | 6 |
| Hawaiian Electric Industries, Inc. | HE | 2.85% | 2.90% | 3.40% | 4.22% | 3.81% | 6.71% | BBB- | 7 |
| IDACORP, Inc. | IDA | 2.51% | 2.55% | 2.50% | 3.85% | 3.18% | 5.73% | BBB | 6 |
| MGE Energy, Inc. | MGEE | 1.86% | 1.90% | 4.00% | N/A | 4.00% | 5.90% | AA- | 1 |
| NextEra Energy, Inc. | NEE | 2.20% | 2.29% | 7.99% | 7.98% | 7.99% | 10.27% | A- | 4 |
| NorthWestern Corporation | NWE | 3.17% | 3.22% | 3.23% | 2.75% | 2.99% | 6.21% | BBB | 6 |
| OGE Energy Corp. | OGE | 3.56% | 3.63% | 3.50% | 4.26% | 3.88% | 7.51% | BBB+ | 5 |
| Otter Tail Corporation | OTTR | 2.84% | 2.95% | 9.00% | 7.00% | 8.00% | 10.95% | BBB | 6 |
| Pinnacle West Capital Corporation | PNW | 3.37% | 3.44% | 4.11% | 4.91% | 4.51% | 7.95% | A- | 4 |
| PNM Resources, Inc. | PNM | 2.43% | 2.50% | 6.25% | 5.40% | 5.83% | 8.33% | BBB+ | 5 |
| Portland General Electric Company | POR | 2.75% | 2.81% | 4.80% | 4.78% | 4.79% | 7.60% | BBB+ | 5 |
| PPL Corporation | PPL | 5.09% | 5.10% | 0.50% | N/A | 0.50% | 5.60% | A- | 4 |
| Sempra Energy | SRE | 2.68% | 2.80% | 10.05% | 7.73% | 8.89% | 11.69% | BBB+ | 5 |
| Southern Company | SO | 4.10% | 4.16% | 1.53% | 4.50% | 3.02% | 7.17% | A- | 4 |
| WEC Energy Group, Inc. | WEC | 2.79% | 2.87% | 6.05% | 6.14% | 6.10% | 8.97% | A- | 4 |
| Xcel Energy Inc. | XEL | 2.59% | 2.66% | 6.10% | 5.42% | 5.76% | 8.42% | A- | 4 |
| PROXY GROUP MEAN | | 3.14% | 3.21% | 4.29% | 5.42% | 4.75% | 7.96% | BBB+ | 4.74 |
| PROXY GROUP MEDIAN | | 3.03% | 3.11% | 4.41% | 5.42% | 4.66% | 8.33% | BBB+ | 5.00 |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.00066414 |
| R Square | 4.41E-07 |
| Adjusted R Square | -0.034482302 |
| Standard Error | 0.019542735 |
| Observations | 31 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 4.88527E-09 | 4.8853E-09 | 1.279E-05 | 0.99717086 |
| Residual | 29 | 0.011075636 | 0.00038192 | | |
| Total | 30 | 0.011075641 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.079588298 | 0.015852389 | 5.02058685 | 2.396E-05 | 0.04716652 | 0.1120101 |
| Credit Score | 1.16596E-05 | 0.003260045 | 0.00357651 | 0.9971709 | -0.00665588 | 0.0066792 |

Notes:
[1] Source: Exhibit JRW-7
[2] Equals [1] x (1 + 0.5 x [6])
[3] Source: Exhibit JRW-7
[4] Source: Exhibit JRW-7
[5] Equals Average([3], [4])
[6] Equals [2] + [5]
[7] Source: Exhibit JRW-2. Note: Exh. JRW-2 incorrectly denotes ED as being rated BBB+
[8] AA- = 1; A+ = 2; A = 3; A- = 4; BBB+ = 5; BBB = 6; BBB- = 7

Credit Ratings - Dr. Woolridge's Proxy Group

| Company | Ticker | Moody's Long-Term Issuer | Moody's Corporate Long-Term | S&P Long-Term Issuer | S&P Corporate Long-Term |
|---|---|---|---|---|---|
| **ALLETE, Inc.** | **ALE** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| Superior Water, Light and Power Company | | A3 | | | |
| **Alliant Energy Corporation** | **LNT** | **Baa2** | **Baa2** | **A-** | **A-** |
| Interstate Power and Light Company | | Baa1 | Baa1 | A- | A- |
| Wisconsin Power and Light Company | | A3 | A3 | A | A |
| **Ameren Corporation** | **AEE** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| Ameren Illinois Company | | A3 | A3 | BBB+ | BBB+ |
| Union Electric Company | | Baa1 | Baa1 | BBB+ | BBB+ |
| **American Electric Power Company, Inc.** | **AEP** | | **Baa1** | **A-** | **A-** |
| AEP Texas Inc. | | Baa1 | Baa1 | A- | A- |
| Appalachian Power Company | | Baa1 | Baa1 | A- | A- |
| Indiana Michigan Power Company | | A3 | A3 | A- | A- |
| Kentucky Power Company | | Baa3 | Baa3 | A- | A- |
| Ohio Power Company | | A2 | A2 | A- | A- |
| Public Service Company of Oklahoma | | A3 | A3 | A- | A- |
| Southwestern Electric Power Company | | Baa2 | Baa2 | A- | A- |
| **Avangrid, Inc.** | **AGR** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| New York State Electric & Gas Corporation | | A3 | A3 | A- | A- |
| United Illuminating Company | | Baa1 | Baa1 | A- | A- |
| Rochester Gas and Electric Corporation | | A3 | A3 | A- | A- |
| Central Maine Power Company | | A2 | A2 | A | A |
| **Avista Corporation** | **AVA** | **Baa2** | | **BBB** | |
| Alaska Electric Light and Power | | Baa3 | Baa3 | | |
| **CMS Energy Corporation** | **CMS** | | **Baa1** | **BBB+** | **BBB+** |
| Consumers Energy Company | | | (P)A2 | A- | A- |
| **Consolidated Edison, Inc.** | **ED** | **Baa2** | **Baa2** | **A-** | **A-** |
| Consolidated Edison Company of New York, Inc. | | Baa1 | Baa1 | A- | A- |
| Orange and Rockland Utilities, Inc. | | Baa1 | Baa1 | A- | A- |
| Rockland Electric | | | | A- | A- |
| **Dominion Energy, Inc.** | **D** | | **Baa2** | **BBB+** | **BBB+** |
| Dominion Energy South Carolina, Inc. | | Baa2 | Baa2 | BBB+ | BBB+ |
| Virginia Electric and Power Company | | A2 | A2 | BBB+ | BBB+ |
| **Duke Energy Corporation** | **DUK** | **Baa1** | **Baa1** | **A-** | **A-** |
| Duke Energy Carolinas, LLC | | A1 | A1 | A- | A- |
| Duke Energy Florida, LLC | | A3 | A3 | A- | A- |
| Duke Energy Indiana, LLC | | A2 | A2 | A- | A- |
| Duke Energy Kentucky, Inc. | | | Baa1 | A- | A- |
| Duke Energy Ohio, Inc. | | Baa1 | Baa1 | A- | A- |
| Duke Energy Progress, LLC | | A2 | A2 | A- | A- |
| **Edison International** | **EIX** | **Baa3** | **Baa3** | **BBB** | **BBB** |
| Southern California Edison Company | | Baa2 | Baa2 | BBB | BBB |
| **Entergy Corporation** | **ETR** | **Baa2** | **Baa2** | **BBB+** | **BBB+** |
| Entergy Arkansas, LLC | | Baa1 | Baa1 | A- | A- |
| Entergy Louisiana, LLC | | Baa1 | Baa1 | A- | A- |
| Entergy Mississippi, LLC | | Baa1 | Baa1 | A- | A- |
| Entergy New Orleans, LLC | | Ba1 | Ba1 | BBB+ | BBB+ |
| Entergy Texas, Inc. | | Baa3 | Baa3 | BBB+ | BBB+ |
| **Evergy, Inc.** | **EVRG** | **Baa2** | **Baa2** | **A-** | **A-** |
| Evergy Kansas Central, Inc. | | Baa1 | Baa1 | A- | A- |
| Evergy Kansas South, Inc. | | Baa1 | Baa1 | A- | A- |
| Evergy Metro, Inc. | | Baa1 | Baa1 | A- | A- |
| Evergy Missouri West, Inc. | | Baa2 | Baa2 | A- | A- |
| **Eversource Energy** | **ES** | **Baa1** | **Baa1** | **A-** | **A-** |
| Connecticut Light and Power Company | | A3 | A3 | A | A |
| NSTAR Electric Company | | A1 | A1 | A | A |
| Public Service Company of New Hampshire | | A3 | A3 | A | A |

Credit Ratings - Dr. Woolridge's Proxy Group

| Company | Ticker | Moody's Long-Term Issuer | Moody's Corporate Long-Term | S&P Long-Term Issuer | S&P Corporate Long-Term |
|---|---|---|---|---|---|
| **Exelon Corporation** | **EXC** | **Baa2** | **Baa2** | **BBB+** | **BBB+** |
| Atlantic City Electric Company | | Baa1 | Baa1 | A- | A- |
| Baltimore Gas and Electric Company | | A3 | A3 | A | A |
| Commonwealth Edison Company | | A3 | A3 | A- | A- |
| Delmarva Power & Light Company | | Baa1 | Baa1 | A- | A- |
| PECO Energy Co. | | A2 | A2 | BBB+ | BBB+ |
| Potomac Electric Power Company | | Baa1 | Baa1 | A- | A- |
| **FirstEnergy Corp.** | **FE** | **Baa3** | **Baa3** | **BBB** | **BBB** |
| Cleveland Electric Illuminating Company | | Baa2 | Baa2 | BBB | BBB |
| Jersey Central Power & Light Company | | Baa1 | Baa1 | BBB | BBB |
| Metropolitan Edison Company | | A3 | A3 | BBB | BBB |
| Monongahela Power Company | | Baa2 | Baa2 | BBB | BBB |
| Ohio Edison Company | | A3 | A3 | BBB | BBB |
| Pennsylvania Electric Company | | Baa1 | Baa1 | BBB | BBB |
| Pennsylvania Power Company | | A3 | A3 | BBB | BBB |
| Potomac Edison Company | | Baa2 | Baa2 | BBB | BBB |
| Toledo Edison Company | | Baa1 | Baa1 | BBB | BBB |
| West Penn Power Company | | A3 | A3 | BBB | BBB |
| **Hawaiian Electric Industries, Inc.** | **HE** | | | **BBB-** | **BBB-** |
| Hawaiian Electric Company, Inc. | | Baa2 | Baa2 | BBB- | BBB- |
| Hawaii Electric Light Company | | | | BBB- | BBB- |
| Maui Electric Company, Ltd | | | | BBB- | BBB- |
| **IDACORP, Inc.** | **IDA** | **Baa1** | **Baa1** | **BBB** | **BBB** |
| Idaho Power Company | | A3 | A3 | BBB | BBB |
| **MGE Energy, Inc.** | **MGEE** | | | | |
| Madison Gas and Electric Company | | A1 | A1 | AA- | AA- |
| **NextEra Energy, Inc.** | **NEE** | **Baa1** | **Baa1** | **A-** | **A-** |
| Florida Power & Light Company | | A1 | A1 | A | A |
| Gulf Power Company | | A2 | A2 | A | A |
| **NorthWestern Corporation** | **NWE** | | **Baa2** | **BBB** | **BBB** |
| **OGE Energy Corp.** | **OGE** | | **(P)Baa1** | **BBB+** | **BBB+** |
| Oklahoma Gas and Electric Company | | A3 | A3 | A- | A- |
| **Otter Tail Corporation** | **OTTR** | **Baa2** | **Baa2** | **BBB** | **BBB** |
| Otter Tail Power Company | | A3 | A3 | BBB+ | BBB+ |
| **Pinnacle West Capital Corporation** | **PNW** | **A3** | **A3** | **A-** | **A-** |
| Arizona Public Service Company | | A2 | A2 | A- | A- |
| **PNM Resources, Inc.** | **PNM** | **Baa3** | **Baa3** | **BBB** | **BBB** |
| Public Service Company of New Mexico | | Baa2 | Baa2 | BBB | BBB |
| Texas-New Mexico Power Company | | A3 | A3 | BBB+ | BBB+ |
| **Portland General Electric Company** | **POR** | **A3** | **A3** | **BBB+** | **BBB+** |
| **PPL Corporation** | **PPL** | **Baa2** | **Baa2** | **A-** | **A-** |
| Kentucky Utilities Company | | A3 | A3 | A- | A- |
| LG&E and KU Energy LLC | | Baa1 | Baa1 | A- | A- |
| Louisville Gas and Electric Company | | A3 | A3 | A- | A- |
| PPL Electric Utilities Corporation | | A3 | A3 | A- | A- |
| **Sempra Energy** | **SRE** | **Baa1** | **Baa1** | **BBB+** | **BBB+** |
| Oncor Electric Delivery Company LLC | | | A2 | A | A |
| San Diego Gas & Electric Company | | Baa1 | Baa1 | BBB+ | BBB+ |
| **Southern Company** | **SO** | | **Baa2** | **A-** | **A-** |
| Alabama Power Company | | A1 | A1 | A | A |
| Georgia Power Company | | Baa1 | Baa1 | A- | A- |
| Mississippi Power Company | | Baa2 | Baa2 | A- | A- |
| **WEC Energy Group, Inc.** | **WEC** | **Baa1** | **Baa1** | **A-** | **A-** |
| Wisconsin Electric Power Company | | A2 | A2 | A- | A- |
| Wisconsin Public Service Corporation | | A2 | A2 | A- | A- |
| **Xcel Energy Inc.** | **XEL** | **Baa1** | **Baa1** | **A-** | **A-** |
| Northern States Power Company - MN | | A2 | A2 | A- | A- |
| Northern States Power Company - WI | | | (P)A2 | A- | A- |
| Public Service Company of Colorado | | A3 | A3 | A- | A- |
| Southwestern Public Service Company | | Baa2 | Baa2 | A- | A- |

Source: S&P Global Market Intelligence

Hypothetical Example: Flotation Cost Recovery

| | |
|---|---|
| Return on Equity | 10.50% |
| Flotation Costs | 2.69% |
| Market Value | $ 25.00 |
| Dividend Yield | 4.25% |
| Growth Rate | 6.25% |
| Adjusted ROE | 10.62% |
| **Flotation Cost Recovery:** | **No** |
| **DCF Estimate** | **10.38%** |

| | Common Stock | Retained Earnings | Book Value | Market Price | Market/ Book Value | Earnings Per Share | Dividends Per Share | Payout Ratio |
|---|---|---|---|---|---|---|---|---|
| 1 | $ 24.33 | | $ 24.33 | $ 25.00 | 1.0277 | $ 2.55 | $ 1.06 | 41.60% |
| 2 | $ 24.33 | $ 1.49 | $ 25.82 | $ 26.53 | 1.0277 | $ 2.71 | $ 1.13 | 41.60% |
| 3 | $ 24.33 | $ 3.08 | $ 27.40 | $ 28.16 | 1.0277 | $ 2.88 | $ 1.20 | 41.60% |
| 4 | $ 24.33 | $ 4.76 | $ 29.08 | $ 29.89 | 1.0277 | $ 3.05 | $ 1.27 | 41.60% |
| 5 | $ 24.33 | $ 6.54 | $ 30.87 | $ 31.72 | 1.0277 | $ 3.24 | $ 1.35 | 41.60% |
| 6 | $ 24.33 | $ 8.43 | $ 32.76 | $ 33.67 | 1.0277 | $ 3.44 | $ 1.43 | 41.60% |
| 7 | $ 24.33 | $ 10.44 | $ 34.77 | $ 35.73 | 1.0277 | $ 3.65 | $ 1.52 | 41.60% |
| 8 | $ 24.33 | $ 12.57 | $ 36.90 | $ 37.92 | 1.0277 | $ 3.87 | $ 1.61 | 41.60% |
| 9 | $ 24.33 | $ 14.84 | $ 39.16 | $ 40.25 | 1.0277 | $ 4.11 | $ 1.71 | 41.60% |
| 10 | $ 24.33 | $ 17.24 | $ 41.56 | $ 42.71 | 1.0277 | $ 4.36 | $ 1.82 | 41.60% |
| | Growth Rate | | 6.13% | 6.13% | | 6.13% | 6.13% | |

| | |
|---|---|
| Return on Equity | 10.50% |
| Flotation Costs | 2.69% |
| Market Value | $ 25.00 |
| Dividend Yield | 4.25% |
| Growth Rate | 6.25% |
| Adjusted ROE | 10.62% |
| **Flotation Cost Recovery:** | **Yes** |
| **DCF Estimate** | **10.50%** |

| | Common Stock | Retained Earnings | Book Value | Market Price | Market/ Book Value | Earnings Per Share | Dividends Per Share | Payout Ratio |
|---|---|---|---|---|---|---|---|---|
| 1 | $ 24.33 | | $ 24.33 | $ 25.00 | 1.0277 | $ 2.58 | $ 1.06 | 41.14% |
| 2 | $ 24.33 | $ 1.52 | $ 25.85 | $ 26.56 | 1.0277 | $ 2.74 | $ 1.13 | 41.14% |
| 3 | $ 24.33 | $ 3.14 | $ 27.46 | $ 28.22 | 1.0277 | $ 2.92 | $ 1.20 | 41.14% |
| 4 | $ 24.33 | $ 4.85 | $ 29.18 | $ 29.99 | 1.0277 | $ 3.10 | $ 1.27 | 41.14% |
| 5 | $ 24.33 | $ 6.68 | $ 31.00 | $ 31.86 | 1.0277 | $ 3.29 | $ 1.35 | 41.14% |
| 6 | $ 24.33 | $ 8.61 | $ 32.94 | $ 33.85 | 1.0277 | $ 3.50 | $ 1.44 | 41.14% |
| 7 | $ 24.33 | $ 10.67 | $ 35.00 | $ 35.97 | 1.0277 | $ 3.72 | $ 1.53 | 41.14% |
| 8 | $ 24.33 | $ 12.86 | $ 37.19 | $ 38.22 | 1.0277 | $ 3.95 | $ 1.62 | 41.14% |
| 9 | $ 24.33 | $ 15.18 | $ 39.51 | $ 40.60 | 1.0277 | $ 4.20 | $ 1.73 | 41.14% |
| 10 | $ 24.33 | $ 17.65 | $ 41.98 | $ 43.14 | 1.0277 | $ 4.46 | $ 1.83 | 41.14% |
| | Growth Rate | | 6.25% | 6.25% | | 6.25% | 6.25% | |

Dr. Woolridge's Proxy Group Capital Structure - Consolidated

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 57.26% | 58.49% | 58.29% | 59.20% | 58.22% | 58.12% | 58.26% | 57.91% | 58.22% |
| Alliant Energy Corporation | LNT | 44.45% | 43.24% | 45.34% | 45.45% | 44.27% | 44.24% | 46.28% | 46.19% | 44.93% |
| Ameren Corporation | AEE | 47.18% | 47.55% | 47.28% | 47.49% | 48.09% | 46.61% | 47.67% | 47.52% | 47.42% |
| American Electric Power Co. | AEP | 42.00% | 41.85% | 42.65% | 44.60% | 45.50% | 45.94% | 46.27% | 46.00% | 44.35% |
| Avangrid, Inc. | AGR | 68.13% | 69.00% | 71.77% | 72.39% | 72.92% | 72.91% | 73.84% | 73.70% | 71.83% |
| Avista Corporation | AVA | 47.72% | 48.68% | 48.46% | 48.08% | 47.74% | 47.92% | 49.17% | 48.72% | 48.31% |
| CMS Energy Corporation | CMS | 27.24% | 28.04% | 28.66% | 28.93% | 30.32% | 30.65% | 30.71% | 30.09% | 29.33% |
| Consolidated Edison, Inc. | ED | 46.91% | 46.54% | 46.68% | 47.97% | 48.89% | 47.87% | 49.42% | 49.03% | 47.91% |
| Dominion Energy, Inc. | D | 41.58% | 39.80% | 39.97% | 36.59% | 34.36% | 34.00% | 33.75% | 33.50% | 36.69% |
| Duke Energy Corporation | DUK | 42.74% | 42.95% | 43.23% | 44.55% | 44.34% | 44.64% | 44.10% | 44.39% | 43.87% |
| Edison International | EIX | 41.88% | 38.51% | 38.65% | 41.55% | 45.13% | 45.13% | 45.79% | 49.05% | 43.21% |
| Entergy Corporation | ETR | 36.10% | 35.69% | 33.75% | 35.33% | 33.72% | 33.54% | 32.09% | 34.61% | 34.35% |
| Evergy, Inc. | EVRG | 48.39% | 54.82% | 53.99% | 57.30% | 58.99% | 59.19% | NA | 50.40% | 54.72% |
| Eversource Energy | ES | 44.79% | 45.21% | 45.82% | 45.55% | 46.41% | 46.38% | 46.03% | 47.33% | 45.94% |
| Exelon Corporation | EXC | 45.54% | 45.57% | 45.54% | 46.19% | 46.51% | 46.77% | 46.70% | 46.32% | 46.14% |
| FirstEnergy Corporation | FE | 26.62% | 26.94% | 26.43% | 26.98% | 27.72% | 29.99% | 28.73% | 16.94% | 26.29% |
| Hawaiian Electric Industries | HE | 51.16% | 50.63% | 50.09% | 52.91% | 53.77% | 53.40% | 54.66% | 54.75% | 52.67% |
| IDACORP, Inc. | IDA | 57.30% | 56.70% | 56.47% | 56.37% | 56.35% | 55.56% | 53.48% | 56.32% | 56.07% |
| MGE Energy, Inc. | MGEE | 62.36% | 61.80% | 61.65% | 62.04% | 61.94% | 65.38% | 65.12% | 64.81% | 63.14% |
| NextEra Energy, Inc. | NEE | 48.39% | 48.80% | 51.30% | 53.48% | 53.56% | 52.42% | 52.81% | 45.88% | 50.83% |
| NorthWestern Corporation | NWE | 47.67% | 47.94% | 48.59% | 47.76% | 48.24% | 48.28% | 47.34% | 49.74% | 48.19% |
| OGE Energy Corp. | OGE | 56.36% | 55.28% | 57.44% | 56.00% | 56.15% | 56.46% | 56.16% | 56.22% | 56.26% |
| Otter Tail Corporation | OTTR | 55.26% | 54.95% | 54.78% | 55.26% | 55.14% | 54.77% | 54.54% | 58.69% | 55.42% |
| Pinnacle West Capital Corp. | PNW | 50.18% | 49.92% | 49.98% | 50.41% | 51.27% | 51.22% | 50.74% | 50.68% | 50.55% |
| PNM Resources, Inc. | PNM | 35.82% | 35.57% | 35.23% | 38.74% | 40.39% | 39.91% | 39.47% | 41.02% | 38.27% |
| Portland General Electric Company | POR | 49.82% | 49.72% | 50.27% | 50.28% | 50.60% | 50.40% | 50.24% | 49.90% | 50.15% |
| PPL Corporation | PPL | 35.49% | 36.12% | 36.25% | 36.14% | 36.78% | 35.50% | 35.32% | 34.76% | 35.80% |
| Sempra Energy | SRE | 41.40% | 38.85% | 40.20% | 39.71% | 39.56% | 38.70% | 38.37% | 41.48% | 39.78% |
| Southern Company | SO | 36.80% | 37.54% | 37.15% | 36.01% | 35.89% | 34.58% | 34.10% | 33.32% | 35.67% |
| WEC Energy Group | WEC | 46.35% | 48.28% | 48.18% | 48.59% | 50.74% | 50.58% | 50.24% | 49.67% | 49.08% |
| Xcel Energy Inc. | XEL | 40.20% | 40.11% | 40.79% | 42.99% | 43.09% | 41.88% | 43.56% | 43.34% | 42.00% |
| Mean | | 45.91% | 45.97% | 46.29% | 46.93% | 47.31% | 47.19% | 46.83% | 46.85% | 46.69% |

Dr. Woolridge's Proxy Group Capital Structure - Consolidated

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 42.74% | 41.51% | 41.71% | 40.80% | 41.78% | 41.88% | 41.74% | 42.09% | 41.78% |
| Alliant Energy Corporation | LNT | 55.55% | 56.76% | 54.66% | 54.55% | 55.73% | 55.76% | 53.72% | 53.81% | 55.07% |
| Ameren Corporation | AEE | 52.82% | 52.45% | 52.72% | 52.51% | 51.91% | 53.39% | 52.33% | 52.48% | 52.58% |
| American Electric Power Co. | AEP | 58.00% | 58.15% | 57.35% | 55.40% | 54.50% | 54.06% | 53.73% | 54.00% | 55.65% |
| Avangrid, Inc. | AGR | 31.87% | 31.00% | 28.23% | 27.61% | 27.08% | 27.09% | 26.16% | 26.30% | 28.17% |
| Avista Corporation | AVA | 52.28% | 51.32% | 51.54% | 51.92% | 52.26% | 52.08% | 50.83% | 51.28% | 51.69% |
| CMS Energy Corporation | CMS | 72.76% | 71.96% | 71.34% | 71.07% | 69.68% | 69.35% | 69.29% | 69.91% | 70.67% |
| Consolidated Edison, Inc. | ED | 53.09% | 53.46% | 53.32% | 52.03% | 51.11% | 52.13% | 50.58% | 50.97% | 52.09% |
| Dominion Energy, Inc. | D | 58.42% | 60.20% | 60.03% | 63.41% | 65.64% | 66.00% | 66.25% | 66.50% | 63.31% |
| Duke Energy Corporation | DUK | 57.26% | 57.05% | 56.77% | 55.45% | 55.66% | 55.36% | 55.90% | 55.61% | 56.13% |
| Edison International | EIX | 58.12% | 61.49% | 61.35% | 58.45% | 54.87% | 54.87% | 54.21% | 50.95% | 56.79% |
| Entergy Corporation | ETR | 63.90% | 64.31% | 66.25% | 64.67% | 66.28% | 66.46% | 67.91% | 65.39% | 65.65% |
| Evergy, Inc. | EVRG | 51.61% | 45.18% | 46.01% | 42.70% | 41.01% | 40.81% | NA | 49.60% | 45.28% |
| Eversource Energy | ES | 55.21% | 54.79% | 54.18% | 54.45% | 53.59% | 53.62% | 53.97% | 52.67% | 54.06% |
| Exelon Corporation | EXC | 54.46% | 54.43% | 54.46% | 53.81% | 53.49% | 53.23% | 53.30% | 53.68% | 53.86% |
| FirstEnergy Corporation | FE | 73.38% | 73.06% | 73.57% | 73.02% | 72.28% | 70.01% | 71.27% | 83.06% | 73.71% |
| Hawaiian Electric Industries | HE | 48.84% | 49.37% | 49.91% | 47.09% | 46.23% | 46.60% | 45.34% | 45.25% | 47.33% |
| IDACORP, Inc. | IDA | 42.70% | 43.30% | 43.53% | 43.63% | 43.65% | 44.44% | 46.52% | 43.68% | 43.93% |
| MGE Energy, Inc. | MGEE | 37.64% | 38.20% | 38.35% | 37.96% | 38.06% | 34.62% | 34.88% | 35.19% | 36.86% |
| NextEra Energy, Inc. | NEE | 51.61% | 51.20% | 48.70% | 46.52% | 46.44% | 47.58% | 47.19% | 54.12% | 49.17% |
| NorthWestern Corporation | NWE | 52.33% | 52.06% | 51.41% | 52.24% | 51.76% | 51.72% | 52.66% | 50.26% | 51.81% |
| OGE Energy Corp. | OGE | 43.64% | 44.72% | 42.56% | 44.00% | 43.85% | 43.54% | 43.84% | 43.78% | 43.74% |
| Otter Tail Corporation | OTTR | 44.74% | 45.05% | 45.22% | 44.74% | 44.86% | 45.23% | 45.46% | 41.31% | 44.58% |
| Pinnacle West Capital Corp. | PNW | 49.82% | 50.08% | 50.02% | 49.59% | 48.73% | 48.78% | 49.26% | 49.32% | 49.45% |
| PNM Resources, Inc. | PNM | 64.18% | 64.43% | 64.77% | 61.26% | 59.61% | 60.09% | 60.53% | 58.98% | 61.73% |
| Portland General Electric Company | POR | 50.18% | 50.28% | 49.73% | 49.72% | 49.40% | 49.60% | 49.76% | 50.10% | 49.85% |
| PPL Corporation | PPL | 64.51% | 63.88% | 63.75% | 63.86% | 63.22% | 64.50% | 64.68% | 65.24% | 64.20% |
| Sempra Energy | SRE | 58.60% | 61.15% | 59.80% | 60.29% | 60.44% | 61.30% | 61.63% | 58.52% | 60.22% |
| Southern Company | SO | 63.20% | 62.46% | 62.85% | 63.99% | 64.11% | 65.42% | 65.90% | 66.68% | 64.33% |
| WEC Energy Group | WEC | 53.65% | 51.72% | 51.82% | 51.41% | 49.26% | 49.42% | 49.76% | 50.33% | 50.92% |
| Xcel Energy Inc. | XEL | 59.80% | 59.89% | 59.21% | 57.01% | 56.91% | 58.12% | 56.44% | 56.66% | 58.00% |
| Mean | | 54.09% | 54.03% | 53.71% | 53.07% | 52.69% | 52.81% | 53.17% | 53.15% | 53.31% |

Dr. Woolridge's Proxy Group Capital Structure - Operating Company Level

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 58.68% | 59.66% | 59.53% | 59.12% | 58.50% | 58.84% | 63.09% | 62.51% | 59.99% |
| Alliant Energy Corporation | LNT | 51.73% | 50.38% | 53.18% | 53.11% | 51.13% | 51.00% | 49.74% | 49.77% | 51.26% |
| Ameren Corporation | AEE | 53.67% | 53.03% | 52.81% | 52.69% | 53.22% | 52.01% | 53.04% | 52.65% | 52.89% |
| American Electric Power Co. | AEP | 49.91% | 48.80% | 49.62% | 49.40% | 48.68% | 48.52% | 48.60% | 48.91% | 49.06% |
| Avangrid, Inc. | AGR | 54.38% | 56.33% | 56.51% | 55.72% | 56.13% | 54.93% | 56.55% | 55.69% | 55.78% |
| Avista Corporation | AVA | 55.80% | 56.32% | 56.10% | 55.09% | 55.75% | 55.76% | 56.34% | 55.76% | 55.86% |
| CMS Energy Corporation | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison, Inc. | ED | 49.85% | 49.08% | 48.75% | 47.97% | 48.38% | 48.73% | 49.75% | 49.23% | 48.97% |
| Dominion Energy, Inc. | D | 53.56% | 50.98% | 50.47% | 48.75% | 51.63% | 51.12% | 50.17% | 50.62% | 50.91% |
| Duke Energy Corporation | DUK | 52.89% | 54.48% | 53.14% | 54.35% | 55.03% | 54.94% | 54.46% | 54.30% | 54.20% |
| Edison International | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Corporation | ETR | 49.10% | 48.19% | 48.81% | 50.11% | 49.96% | 49.95% | 48.60% | 48.97% | 49.21% |
| Evergy, Inc. | EVRG | 60.28% | 60.51% | 58.16% | 59.56% | 59.86% | 58.51% | 58.73% | 58.62% | 59.28% |
| Eversource Energy | ES | 49.53% | 49.38% | 54.22% | 53.28% | 51.03% | 50.14% | 54.05% | 54.60% | 52.03% |
| Exelon Corporation | EXC | 51.77% | 52.46% | 52.41% | 51.93% | 51.85% | 52.40% | 52.25% | 52.10% | 52.15% |
| FirstEnergy Corporation | FE | 55.88% | 55.95% | 56.46% | 56.61% | 58.05% | 57.49% | 56.37% | 55.73% | 56.57% |
| Hawaiian Electric Industries | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| IDACORP, Inc. | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| MGE Energy, Inc. | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| NextEra Energy, Inc. | NEE | 56.15% | 61.22% | 61.05% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 61.20% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| OGE Energy Corp. | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Corporation | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Pinnacle West Capital Corp. | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| PNM Resources, Inc. | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| PPL Corporation | PPL | 53.84% | 53.74% | 55.38% | 55.06% | 54.92% | 54.59% | 54.52% | 54.67% | 54.59% |
| Sempra Energy | SRE | 56.17% | 56.30% | 53.82% | 53.29% | 53.13% | 54.39% | 54.20% | 53.27% | 54.32% |
| Southern Company | SO | 52.36% | 52.93% | 52.80% | 54.21% | 51.50% | 50.31% | 49.98% | 47.67% | 51.47% |
| WEC Energy Group | WEC | 55.79% | 56.71% | 55.73% | 53.46% | 58.30% | 57.72% | 61.62% | 54.62% | 56.74% |
| Xcel Energy Inc. | XEL | 53.98% | 54.70% | 54.51% | 54.22% | 53.37% | 53.63% | 54.15% | 53.95% | 54.06% |
| Mean | | 53.55% | 53.55% | 53.50% | 53.37% | 53.64% | 53.39% | 53.66% | 53.54% | 53.52% |

Operating Company Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 59.33% | 60.94% | 60.87% | 61.39% | 60.43% | 60.33% | 60.38% | 60.04% | 60.46% |
| Superior Water, Light and Power Company | ALE | 58.03% | 58.38% | 58.19% | 56.86% | 56.58% | 57.34% | 65.80% | 64.99% | 59.52% |
| Interstate Power and Light Company | LNT | 50.06% | 51.76% | 53.33% | 53.52% | 49.64% | 50.47% | 49.92% | 50.31% | 51.13% |
| Wisconsin Power and Light Company | LNT | 53.40% | 49.01% | 53.03% | 52.69% | 52.62% | 51.52% | 49.57% | 49.23% | 51.38% |
| Ameren Illinois Company | AEE | 54.46% | 54.05% | 53.65% | 52.86% | 53.18% | 52.74% | 54.24% | 53.38% | 53.57% |
| Union Electric Company | AEE | 52.88% | 52.00% | 51.96% | 52.52% | 53.26% | 51.28% | 51.84% | 51.92% | 52.21% |
| AEP Texas Inc. | AEP | 46.97% | 46.32% | 47.54% | 45.38% | 43.80% | 43.20% | 46.75% | 45.14% | 45.64% |
| Appalachian Power Company | AEP | 48.74% | 48.19% | 47.77% | 49.51% | 49.30% | 48.93% | 49.35% | 48.72% | 48.81% |
| Indiana Michigan Power Company | AEP | 46.51% | 45.83% | 45.43% | 44.62% | 44.53% | 44.15% | 46.64% | 46.33% | 45.50% |
| Kentucky Power Company | AEP | 46.94% | 46.50% | 46.42% | 45.72% | 45.28% | 44.89% | 44.40% | 43.52% | 45.46% |
| Kingsport Power Company | AEP | 54.24% | 50.18% | 51.54% | 50.79% | 50.71% | 47.69% | 47.28% | 46.53% | 49.87% |
| Ohio Power Company | AEP | 53.63% | 52.92% | 58.86% | 57.80% | 56.85% | 57.11% | 52.91% | 58.63% | 56.09% |
| Public Service Company of Oklahoma | AEP | 49.89% | 48.02% | 47.19% | 49.16% | 49.55% | 48.59% | 48.10% | 48.50% | 48.62% |
| Southwestern Electric Power Company | AEP | 48.63% | 47.45% | 47.59% | 46.97% | 43.43% | 47.91% | 47.72% | 48.52% | 47.28% |
| Wheeling Power Company | AEP | 53.66% | 53.83% | 54.27% | 54.62% | 54.70% | 54.19% | 54.27% | 54.26% | 54.23% |
| Central Maine Power Company | AGR | 62.19% | 61.96% | 63.51% | 63.21% | 64.17% | 63.53% | 64.18% | 63.82% | 63.32% |
| New York State Electric & Gas Corporation | AGR | 48.79% | 55.84% | 55.93% | 54.30% | 53.95% | 50.99% | 54.51% | 53.30% | 53.45% |
| Rochester Gas and Electric Corporation | AGR | 50.50% | 50.25% | 49.96% | 48.89% | 48.16% | 47.77% | 50.80% | 49.63% | 49.50% |
| United Illuminating Company | AGR | 56.05% | 57.26% | 56.65% | 56.46% | 58.23% | 57.43% | 56.70% | 56.00% | 56.85% |
| Alaska Electric Light and Power Company | AVA | 61.28% | 61.24% | 61.02% | 60.29% | 61.94% | 61.78% | 61.53% | 60.77% | 61.23% |
| Avista Corporation | AVA | 50.33% | 51.40% | 51.18% | 49.89% | 49.55% | 49.74% | 51.16% | 50.75% | 50.50% |
| Consumers Energy Company | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison Company of New York, Inc. | ED | 49.29% | 48.92% | 48.30% | 47.52% | 48.33% | 46.72% | 48.66% | 48.22% | 48.24% |
| Orange and Rockland Utilities, Inc. | ED | 50.40% | 49.25% | 49.21% | 48.41% | 48.44% | 50.74% | 50.83% | 50.25% | 49.69% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 53.33% | 53.30% | 52.42% | 52.62% | 53.64% | 52.81% | 51.03% | 51.71% | 52.61% |
| Dominion Energy South Carolina, Inc. | D | 53.80% | 48.67% | 48.52% | 44.88% | 49.63% | 49.44% | 49.30% | 49.54% | 49.22% |
| Duke Energy Carolinas, LLC | DUK | 51.80% | 52.94% | 52.32% | 51.78% | 52.64% | 52.10% | 51.70% | 52.98% | 52.28% |
| Duke Energy Florida, LLC | DUK | 52.82% | 51.55% | 50.56% | 50.04% | 49.65% | 48.79% | 49.92% | 49.25% | 50.32% |
| Duke Energy Indiana, LLC | DUK | 51.52% | 54.83% | 54.29% | 53.26% | 52.79% | 52.64% | 52.54% | 51.94% | 52.98% |
| Duke Energy Kentucky, Inc. | DUK | 45.44% | 53.04% | 52.81% | 51.95% | 56.58% | 55.79% | 53.72% | 53.11% | 52.80% |
| Duke Energy Ohio, Inc. | DUK | 64.90% | 64.45% | 59.29% | 68.09% | 67.73% | 67.10% | 66.06% | 66.24% | 65.48% |
| Duke Energy Progress, LLC | DUK | 50.86% | 50.09% | 49.60% | 51.00% | 50.76% | 53.22% | 52.82% | 52.27% | 51.33% |
| Southern California Edison Company | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Arkansas, LLC | ETR | 47.72% | 46.49% | 47.04% | 49.42% | 49.38% | 48.29% | 45.88% | 45.95% | 47.52% |
| Entergy Louisiana, LLC | ETR | 47.13% | 46.32% | 45.79% | 47.37% | 46.77% | 46.97% | 44.58% | 47.43% | 46.55% |
| Entergy Mississippi, LLC | ETR | 48.35% | 44.93% | 49.41% | 49.11% | 50.10% | 49.10% | 48.32% | 47.85% | 48.40% |
| Entergy New Orleans, LLC | ETR | 53.69% | 52.40% | 51.69% | 51.19% | 50.93% | 54.02% | 53.43% | 53.16% | 52.56% |
| Entergy Texas, Inc. | ETR | 48.63% | 50.79% | 50.13% | 53.46% | 52.61% | 51.38% | 50.79% | 50.45% | 51.03% |
| Evergy Kansas South, Inc. | EVRG | 81.84% | 81.49% | 75.13% | 74.97% | 74.91% | 74.45% | 74.29% | 74.18% | 76.41% |
| Evergy Metro, Inc. | EVRG | 50.43% | 49.62% | 46.04% | 49.49% | 49.50% | 48.88% | 49.25% | 49.15% | 49.05% |
| Evergy Missouri West, Inc. | EVRG | 51.18% | 51.74% | 52.68% | 54.71% | 55.70% | 52.03% | 52.63% | 52.40% | 52.88% |
| Westar Energy (KPL) | EVRG | 57.66% | 59.18% | 58.80% | 59.08% | 59.34% | 58.68% | 58.75% | 58.74% | 58.78% |
| Connecticut Light and Power Company | ES | 54.12% | 55.38% | 58.18% | 56.18% | 54.49% | 53.85% | 50.40% | 53.82% | 54.55% |
| NSTAR Electric Company | ES | 53.81% | 52.74% | 56.08% | 55.74% | 55.50% | 54.51% | 53.83% | 53.85% | 54.51% |
| Public Service Company of New Hampshire | ES | 40.64% | 40.02% | 48.38% | 47.92% | 43.11% | 42.06% | 57.93% | 57.30% | 47.17% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 53.43% | 53.43% |
| Atlantic City Electric Company | EXC | 49.38% | 49.47% | 49.30% | 49.14% | 50.38% | 49.46% | 49.14% | 49.19% | 49.43% |
| Baltimore Gas and Electric Company | EXC | 51.89% | 54.36% | 54.43% | 53.67% | 52.85% | 55.34% | 55.36% | 54.77% | 54.08% |
| Commonwealth Edison Company | EXC | 55.61% | 55.29% | 55.00% | 55.06% | 54.72% | 55.36% | 54.96% | 54.85% | 55.11% |
| Delmarva Power & Light Company | EXC | 50.18% | 50.20% | 50.18% | 49.98% | 50.11% | 49.86% | 50.35% | 50.38% | 50.16% |
| PECO Energy Co. | EXC | 53.37% | 55.20% | 55.13% | 53.72% | 52.82% | 54.28% | 53.77% | 53.54% | 53.98% |
| Potomac Electric Power Company | EXC | 50.21% | 50.24% | 50.41% | 50.01% | 50.24% | 50.08% | 49.94% | 49.89% | 50.13% |
| Cleveland Electric Illuminating Company | FE | 55.74% | 55.49% | 55.54% | 55.44% | 56.50% | 56.31% | 55.48% | 55.27% | 55.72% |
| Jersey Central Power & Light Company | FE | 68.74% | 68.23% | 68.08% | 69.46% | 69.34% | 68.81% | 65.52% | 65.30% | 67.93% |
| Metropolitan Edison Company | FE | 49.72% | 48.46% | 47.78% | 53.21% | 54.25% | 53.10% | 52.18% | 52.33% | 51.38% |
| Monongahela Power Company | FE | 49.98% | 49.07% | 49.05% | 48.87% | 50.71% | 51.53% | 50.57% | 49.15% | 49.87% |
| Ohio Edison Company | FE | 69.16% | 71.42% | 70.82% | 69.93% | 69.14% | 67.33% | 66.89% | 64.91% | 68.70% |
| Pennsylvania Electric Company | FE | 51.78% | 50.93% | 53.85% | 53.89% | 54.01% | 53.90% | 53.09% | 52.06% | 52.94% |
| Pennsylvania Power Company | FE | 53.09% | 51.71% | 50.69% | 49.03% | 58.27% | 56.89% | 55.70% | 53.82% | 53.65% |
| Potomac Edison Company | FE | 53.69% | 52.99% | 53.29% | 52.35% | 52.92% | 52.65% | 52.64% | 51.59% | 52.77% |
| Toledo Edison Company | FE | 60.76% | 60.57% | 60.78% | 60.43% | 62.25% | 62.25% | 60.60% | 60.04% | 60.96% |
| West Penn Power Company | FE | 46.11% | 50.63% | 54.68% | 53.50% | 53.14% | 52.09% | 51.09% | 52.82% | 51.76% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| Madison Gas and Electric Company | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| Florida Power & Light Company | NEE | 59.78% | 61.30% | 64.03% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 62.03% |
| Gulf Power Company | NEE | 52.52% | 61.15% | 58.06% | NA | NA | NA | NA | NA | 57.24% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| Oklahoma Gas and Electric Company | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Power Company | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Arizona Public Service Company | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| Public Service Company of New Mexico | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Kentucky Utilities Company | PPL | 52.97% | 52.81% | 55.44% | 54.85% | 54.76% | 54.51% | 54.08% | 54.00% | 54.18% |
| Louisville Gas and Electric Company | PPL | 54.10% | 53.88% | 56.16% | 55.80% | 55.35% | 54.97% | 54.46% | 55.42% | 55.02% |
| PPL Electric Utilities Corporation | PPL | 54.44% | 54.51% | 54.52% | 54.52% | 54.65% | 54.28% | 55.04% | 54.57% | 54.57% |
| Oncor Electric Delivery Company LLC | SRE | 54.91% | 57.43% | 59.79% | 59.47% | 59.29% | 62.31% | 60.34% | 58.86% | 59.05% |
| San Diego Gas & Electric Company | SRE | 57.43% | 55.17% | 56.60% | 55.79% | 55.17% | 54.47% | 55.92% | 55.09% | 55.71% |
| Sharyland Utilities, LLC | SRE | NA | NA | 45.05% | 44.62% | 44.92% | 46.39% | 46.34% | 45.86% | 45.53% |
| Alabama Power Company | SO | 51.45% | 52.54% | 52.23% | 47.77% | 48.13% | 47.51% | 48.86% | 47.07% | 49.44% |
| Georgia Power Company | SO | 55.38% | 56.39% | 56.43% | 59.02% | 57.27% | 54.97% | 53.81% | 50.06% | 55.42% |
| Mississippi Power Company | SO | 50.23% | 49.87% | 49.73% | 50.35% | 45.28% | 43.87% | 43.00% | 39.34% | 46.46% |
| Gulf Power Company | SO | NA | NA | NA | 59.73% | 55.34% | 54.90% | 54.27% | 54.19% | 55.69% |
| Upper Michigan Energy Resources Corporation | WEC | 56.09% | 54.45% | 52.54% | 47.01% | 55.08% | 54.53% | 70.04% | 49.85% | 54.95% |
| Wisconsin Electric Power Company | WEC | 56.92% | 56.64% | 55.78% | 56.03% | 59.25% | 59.09% | 56.47% | 55.94% | 57.01% |
| Wisconsin Public Service Corporation | WEC | 54.37% | 59.04% | 58.88% | 57.33% | 60.59% | 59.53% | 58.35% | 58.06% | 58.27% |
| Northern States Power Company - MN | XEL | 51.79% | 53.66% | 53.64% | 52.81% | 52.64% | 52.61% | 52.59% | 52.38% | 52.77% |
| Northern States Power Company - WI | XEL | 53.56% | 53.49% | 53.59% | 53.60% | 48.45% | 53.85% | 53.79% | 53.36% | 52.96% |
| Public Service Company of Colorado | XEL | 56.35% | 57.53% | 56.68% | 56.31% | 56.08% | 54.17% | 56.67% | 56.50% | 56.29% |
| Southwestern Public Service Company | XEL | 54.21% | 54.14% | 54.13% | 54.17% | 56.29% | 53.88% | 53.54% | 53.55% | 54.24% |
| Mean | | 53.41% | 53.55% | 53.64% | 53.51% | 53.69% | 53.41% | 53.60% | 53.23% | 53.52% |

Source: S&P Global Market Intelligence

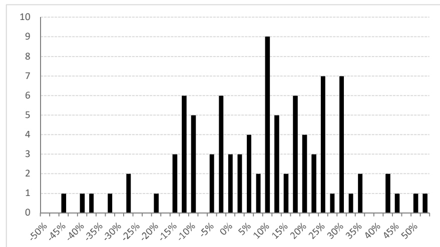
Dr. Woolridge's Proxy Group Capital Structure - Operating Company Level

| Company | Ticker | % Long-Term Debt 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 41.32% | 40.34% | 40.47% | 40.88% | 41.50% | 41.16% | 36.91% | 37.49% | 40.01% |
| Alliant Energy Corporation | LNT | 48.27% | 49.62% | 46.82% | 46.89% | 48.87% | 49.00% | 50.26% | 50.23% | 48.74% |
| Ameren Corporation | AEE | 46.33% | 46.97% | 47.19% | 47.31% | 46.78% | 47.99% | 46.96% | 47.35% | 47.11% |
| American Electric Power Co. | AEP | 50.09% | 51.20% | 50.38% | 50.60% | 51.32% | 51.48% | 51.40% | 51.09% | 50.94% |
| Avangrid, Inc. | AGR | 45.62% | 43.67% | 43.49% | 44.28% | 43.87% | 45.07% | 43.45% | 44.31% | 44.22% |
| Avista Corporation | AVA | 44.20% | 43.68% | 43.90% | 44.91% | 44.25% | 44.24% | 43.66% | 44.24% | 44.14% |
| CMS Energy Corporation | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison, Inc. | ED | 50.15% | 50.92% | 51.25% | 52.03% | 51.62% | 51.27% | 50.25% | 50.77% | 51.03% |
| Dominion Energy, Inc. | D | 46.44% | 49.02% | 49.53% | 51.25% | 48.37% | 48.88% | 49.83% | 49.38% | 49.09% |
| Duke Energy Corporation | DUK | 47.11% | 45.52% | 46.86% | 45.65% | 44.97% | 45.06% | 45.54% | 45.70% | 45.80% |
| Edison International | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Corporation | ETR | 50.90% | 51.81% | 51.19% | 49.89% | 50.04% | 50.05% | 51.40% | 51.03% | 50.79% |
| Evergy, Inc. | EVRG | 39.72% | 39.49% | 41.84% | 40.44% | 40.14% | 41.49% | 41.27% | 41.38% | 40.72% |
| Eversource Energy | ES | 50.47% | 50.62% | 45.78% | 46.72% | 48.97% | 49.86% | 45.95% | 45.40% | 47.97% |
| Exelon Corporation | EXC | 48.23% | 47.54% | 47.59% | 48.07% | 48.15% | 47.60% | 47.75% | 47.90% | 47.85% |
| FirstEnergy Corporation | FE | 44.12% | 44.05% | 43.54% | 43.39% | 41.95% | 42.51% | 43.63% | 44.27% | 43.43% |
| Hawaiian Electric Industries | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| IDACORP, Inc. | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| MGE Energy, Inc. | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| NextEra Energy, Inc. | NEE | 43.85% | 38.78% | 38.95% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 38.80% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| OGE Energy Corp. | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Corporation | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Pinnacle West Capital Corp. | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| PNM Resources, Inc. | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| PPL Corporation | PPL | 46.16% | 46.26% | 44.62% | 44.94% | 45.08% | 45.41% | 45.48% | 45.33% | 45.41% |
| Sempra Energy | SRE | 43.83% | 43.70% | 46.18% | 46.71% | 46.87% | 45.61% | 45.80% | 46.73% | 45.68% |
| Southern Company | SO | 47.64% | 47.07% | 47.20% | 45.79% | 48.50% | 49.69% | 50.02% | 52.33% | 48.53% |
| WEC Energy Group | WEC | 44.21% | 43.29% | 44.27% | 46.54% | 41.70% | 42.28% | 38.38% | 45.38% | 43.26% |
| Xcel Energy Inc. | XEL | 46.02% | 45.30% | 45.49% | 45.78% | 46.63% | 46.37% | 45.85% | 46.05% | 45.94% |
| Mean | | 46.45% | 46.45% | 46.50% | 46.63% | 46.36% | 46.61% | 46.34% | 46.46% | 46.48% |

Operating Company Capital Structure

| Operating Company | Parent | % Long-Term Debt 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE (Minnesota Power) | ALE | 40.67% | 39.06% | 39.13% | 38.61% | 39.57% | 39.67% | 39.62% | 39.96% | 39.54% |
| Superior Water, Light and Power Company | ALE | 41.97% | 41.62% | 41.81% | 43.14% | 43.42% | 42.66% | 34.20% | 35.01% | 40.48% |
| Interstate Power and Light Company | LNT | 49.94% | 48.24% | 46.67% | 46.48% | 50.36% | 49.53% | 50.08% | 49.69% | 48.87% |
| Wisconsin Power and Light Company | LNT | 46.60% | 50.99% | 46.97% | 47.31% | 47.38% | 48.48% | 50.43% | 50.77% | 48.62% |
| Ameren Illinois Company | AEE | 45.54% | 45.95% | 46.35% | 47.14% | 46.82% | 47.26% | 45.76% | 46.62% | 46.43% |
| Union Electric Company | AEE | 47.12% | 48.00% | 48.04% | 47.48% | 46.74% | 48.72% | 48.16% | 48.08% | 47.79% |
| AEP Texas Inc. | AEP | 53.03% | 53.68% | 52.46% | 54.62% | 56.20% | 56.80% | 53.25% | 54.86% | 54.36% |
| Appalachian Power Company | AEP | 51.26% | 51.81% | 52.23% | 50.49% | 50.70% | 51.07% | 50.65% | 51.28% | 51.19% |
| Indiana Michigan Power Company | AEP | 53.49% | 54.17% | 54.57% | 55.38% | 55.47% | 55.85% | 53.36% | 53.67% | 54.50% |
| Kentucky Power Company | AEP | 53.06% | 53.50% | 53.58% | 54.28% | 54.72% | 55.11% | 55.60% | 56.48% | 54.54% |
| Kingsport Power Company | AEP | 45.76% | 49.82% | 48.46% | 49.21% | 49.29% | 52.31% | 52.72% | 53.47% | 50.13% |
| Ohio Power Company | AEP | 46.37% | 47.08% | 41.14% | 42.20% | 43.15% | 42.89% | 47.09% | 41.37% | 43.91% |
| Public Service Company of Oklahoma | AEP | 50.11% | 51.98% | 52.81% | 50.84% | 50.45% | 51.41% | 51.90% | 51.50% | 51.38% |
| Southwestern Electric Power Company | AEP | 51.37% | 52.55% | 52.41% | 53.03% | 56.57% | 52.09% | 52.28% | 51.48% | 52.72% |
| Wheeling Power Company | AEP | 46.34% | 46.17% | 45.73% | 45.38% | 45.30% | 45.81% | 45.73% | 45.74% | 45.77% |
| Central Maine Power Company | AGR | 37.81% | 38.04% | 36.49% | 36.79% | 35.83% | 36.47% | 35.82% | 36.18% | 36.68% |
| New York State Electric & Gas Corporation | AGR | 51.21% | 44.16% | 44.07% | 45.70% | 46.05% | 49.01% | 45.49% | 46.70% | 46.55% |
| Rochester Gas and Electric Corporation | AGR | 49.50% | 49.75% | 50.04% | 51.11% | 51.84% | 52.23% | 49.20% | 50.37% | 50.50% |
| United Illuminating Company | AGR | 43.95% | 42.74% | 43.35% | 43.54% | 41.77% | 42.57% | 43.30% | 44.00% | 43.15% |
| Alaska Electric Light and Power Company | AVA | 38.72% | 38.76% | 38.98% | 39.71% | 38.06% | 38.22% | 38.47% | 39.23% | 38.77% |
| Avista Corporation | AVA | 49.67% | 48.60% | 48.82% | 50.11% | 50.45% | 50.26% | 48.84% | 49.25% | 49.50% |
| Consumers Energy Company | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison Company of New York, Inc. | ED | 50.71% | 51.08% | 51.70% | 52.48% | 51.67% | 53.28% | 51.34% | 51.78% | 51.76% |
| Orange and Rockland Utilities, Inc. | ED | 49.60% | 50.75% | 50.79% | 51.59% | 51.56% | 49.26% | 49.17% | 49.75% | 50.31% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 46.67% | 46.70% | 47.58% | 47.38% | 46.36% | 47.19% | 48.97% | 48.29% | 47.39% |
| Dominion Energy South Carolina, Inc. | D | 46.20% | 51.33% | 51.48% | 55.12% | 50.37% | 50.56% | 50.70% | 50.46% | 50.78% |
| Duke Energy Carolinas, LLC | DUK | 48.20% | 47.06% | 47.68% | 48.22% | 47.36% | 47.90% | 48.30% | 47.02% | 47.72% |
| Duke Energy Florida, LLC | DUK | 47.18% | 48.45% | 49.44% | 49.96% | 50.35% | 51.21% | 50.08% | 50.75% | 49.68% |
| Duke Energy Indiana, LLC | DUK | 48.48% | 45.17% | 45.71% | 46.74% | 47.21% | 47.36% | 47.46% | 48.06% | 47.02% |
| Duke Energy Kentucky, Inc. | DUK | 54.56% | 46.96% | 47.19% | 48.05% | 43.42% | 44.21% | 46.28% | 46.89% | 47.20% |
| Duke Energy Ohio, Inc. | DUK | 35.10% | 35.55% | 40.71% | 31.91% | 32.27% | 32.90% | 33.94% | 33.76% | 34.52% |
| Duke Energy Progress, LLC | DUK | 49.14% | 49.91% | 50.40% | 49.00% | 49.24% | 46.78% | 47.18% | 47.73% | 48.67% |
| Southern California Edison Company | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Arkansas, LLC | ETR | 52.28% | 53.51% | 52.96% | 50.58% | 50.62% | 51.71% | 54.12% | 54.05% | 52.48% |
| Entergy Louisiana, LLC | ETR | 52.87% | 53.68% | 54.21% | 52.63% | 53.23% | 53.03% | 55.42% | 52.57% | 53.45% |
| Entergy Mississippi, LLC | ETR | 51.65% | 55.07% | 50.59% | 50.89% | 49.90% | 50.90% | 51.68% | 52.15% | 51.60% |
| Entergy New Orleans, LLC | ETR | 46.31% | 47.60% | 48.31% | 48.81% | 49.07% | 45.98% | 46.57% | 46.84% | 47.44% |
| Entergy Texas, Inc. | ETR | 51.37% | 49.21% | 49.87% | 46.54% | 47.39% | 48.62% | 49.21% | 49.55% | 48.97% |
| Evergy Kansas South, Inc. | EVRG | 18.16% | 18.51% | 24.87% | 25.03% | 25.09% | 25.55% | 25.71% | 25.82% | 23.59% |
| Evergy Metro, Inc. | EVRG | 49.57% | 50.38% | 53.96% | 50.51% | 50.50% | 51.12% | 50.75% | 50.85% | 50.95% |
| Evergy Missouri West, Inc. | EVRG | 48.82% | 48.26% | 47.32% | 45.29% | 44.30% | 47.97% | 47.37% | 47.60% | 47.12% |
| Westar Energy (KPL) | EVRG | 42.34% | 40.82% | 41.20% | 40.92% | 40.66% | 41.32% | 41.25% | 41.26% | 41.22% |
| Connecticut Light and Power Company | ES | 45.88% | 44.62% | 41.82% | 43.82% | 45.51% | 46.15% | 49.60% | 46.18% | 45.45% |
| NSTAR Electric Company | ES | 46.19% | 47.26% | 43.92% | 44.26% | 44.50% | 45.49% | 46.17% | 46.15% | 45.49% |
| Public Service Company of New Hampshire | ES | 59.36% | 59.98% | 51.62% | 52.08% | 56.89% | 57.94% | 42.07% | 42.70% | 52.83% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 46.57% | 46.57% |
| Atlantic City Electric Company | EXC | 50.62% | 50.53% | 50.70% | 50.86% | 49.62% | 50.54% | 50.86% | 50.81% | 50.57% |
| Baltimore Gas and Electric Company | EXC | 48.11% | 45.64% | 45.57% | 46.33% | 47.15% | 44.66% | 44.64% | 45.23% | 45.92% |
| Commonwealth Edison Company | EXC | 44.39% | 44.71% | 45.00% | 44.94% | 45.28% | 44.64% | 45.04% | 45.15% | 44.89% |
| Delmarva Power & Light Company | EXC | 49.82% | 49.80% | 49.82% | 50.02% | 49.89% | 50.14% | 49.65% | 49.62% | 49.84% |
| PECO Energy Co. | EXC | 46.63% | 44.80% | 44.87% | 46.28% | 47.18% | 45.72% | 46.23% | 46.46% | 46.02% |
| Potomac Electric Power Company | EXC | 49.79% | 49.76% | 49.59% | 49.99% | 49.76% | 49.92% | 50.06% | 50.11% | 49.87% |
| Cleveland Electric Illuminating Company | FE | 44.26% | 44.51% | 44.46% | 44.56% | 43.50% | 43.69% | 44.52% | 44.73% | 44.28% |
| Jersey Central Power & Light Company | FE | 31.26% | 31.77% | 31.92% | 30.54% | 30.66% | 31.19% | 34.48% | 34.70% | 32.07% |
| Metropolitan Edison Company | FE | 50.28% | 51.54% | 52.22% | 46.79% | 45.75% | 46.90% | 47.82% | 47.67% | 48.62% |
| Monongahela Power Company | FE | 50.02% | 50.93% | 50.95% | 51.13% | 49.29% | 48.47% | 49.43% | 50.85% | 50.13% |
| Ohio Edison Company | FE | 30.84% | 28.58% | 29.18% | 30.07% | 30.86% | 32.67% | 33.11% | 35.09% | 31.30% |
| Pennsylvania Electric Company | FE | 48.22% | 49.07% | 46.15% | 46.11% | 45.99% | 46.10% | 46.91% | 47.94% | 47.06% |
| Pennsylvania Power Company | FE | 46.91% | 48.29% | 49.31% | 50.97% | 41.73% | 43.11% | 44.30% | 46.18% | 46.35% |
| Potomac Edison Company | FE | 46.31% | 47.01% | 46.71% | 47.65% | 47.08% | 47.35% | 47.36% | 48.41% | 47.23% |
| Toledo Edison Company | FE | 39.24% | 39.43% | 39.22% | 39.57% | 37.75% | 37.75% | 39.40% | 39.96% | 39.04% |
| West Penn Power Company | FE | 53.89% | 49.37% | 45.32% | 46.50% | 46.86% | 47.91% | 48.91% | 47.18% | 48.24% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| Madison Gas and Electric Company | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| Florida Power & Light Company | NEE | 40.22% | 38.70% | 35.97% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 37.97% |
| Gulf Power Company | NEE | 47.48% | 38.85% | 41.94% | NA | NA | NA | NA | NA | 42.76% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| Oklahoma Gas and Electric Company | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Power Company | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Arizona Public Service Company | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| Public Service Company of New Mexico | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Kentucky Utilities Company | PPL | 47.03% | 47.19% | 44.56% | 45.15% | 45.24% | 45.49% | 45.92% | 46.00% | 45.82% |
| Louisville Gas and Electric Company | PPL | 45.90% | 46.12% | 43.84% | 44.20% | 44.65% | 45.03% | 45.54% | 44.58% | 44.98% |
| PPL Electric Utilities Corporation | PPL | 45.56% | 45.49% | 45.48% | 45.48% | 45.35% | 45.72% | 44.96% | 45.43% | 45.43% |
| Oncor Electric Delivery Company LLC | SRE | 45.09% | 42.57% | 40.21% | 40.53% | 40.71% | 37.69% | 39.66% | 41.14% | 40.95% |
| San Diego Gas & Electric Company | SRE | 42.57% | 44.83% | 43.40% | 44.21% | 44.83% | 45.53% | 44.08% | 44.91% | 44.29% |
| Sharyland Utilities, LLC | SRE | NA | NA | 54.95% | 55.38% | 55.08% | 53.61% | 53.66% | 54.14% | 54.47% |
| Alabama Power Company | SO | 48.55% | 47.46% | 47.77% | 52.23% | 51.87% | 52.49% | 51.14% | 52.93% | 50.56% |
| Georgia Power Company | SO | 44.62% | 43.61% | 43.57% | 40.98% | 42.73% | 45.03% | 46.19% | 49.94% | 44.58% |
| Mississippi Power Company | SO | 49.77% | 50.13% | 50.27% | 49.65% | 54.72% | 56.13% | 57.00% | 60.66% | 53.54% |
| Gulf Power Company | SO | NA | NA | NA | 40.27% | 44.66% | 45.10% | 45.73% | 45.81% | 44.31% |
| Upper Michigan Energy Resources Corporation | WEC | 43.91% | 45.55% | 47.46% | 52.99% | 44.92% | 45.47% | 29.96% | 50.15% | 45.05% |
| Wisconsin Electric Power Company | WEC | 43.08% | 43.36% | 44.22% | 43.97% | 40.75% | 40.91% | 43.53% | 44.06% | 42.99% |
| Wisconsin Public Service Corporation | WEC | 45.63% | 40.96% | 41.12% | 42.67% | 39.41% | 40.47% | 41.65% | 41.94% | 41.73% |
| Northern States Power Company - MN | XEL | 48.21% | 46.34% | 46.36% | 47.19% | 47.36% | 47.39% | 47.41% | 47.62% | 47.23% |
| Northern States Power Company - WI | XEL | 46.44% | 46.51% | 46.41% | 46.40% | 51.55% | 46.15% | 46.21% | 46.64% | 47.04% |
| Public Service Company of Colorado | XEL | 43.65% | 42.47% | 43.32% | 43.69% | 43.92% | 45.83% | 43.33% | 43.50% | 43.71% |
| Southwestern Public Service Company | XEL | 45.79% | 45.86% | 45.87% | 45.83% | 43.71% | 46.12% | 46.46% | 46.45% | 45.76% |
| Mean | | 46.59% | 46.45% | 46.36% | 46.49% | 46.31% | 46.59% | 46.40% | 46.77% | 46.48% |

Frequency Distribution of Market Risk Premium, 1926 - 2019




| Year | Large Company Stocks Total Returns Jan-Dec* | Long-Term Government Bond Income Returns Jan-Dec* | MRP Jan-Dec* |
|---|---|---|---|
| 1926 | 0.1162 | 0.0373 | 0.0789 |
| 1927 | 0.3749 | 0.0341 | 0.3408 |
| 1928 | 0.4361 | 0.0322 | 0.4039 |
| 1929 | -0.0842 | 0.0347 | -0.1189 |
| 1930 | -0.2490 | 0.0332 | -0.2822 |
| 1931 | -0.4334 | 0.0333 | -0.4667 |
| 1932 | -0.0819 | 0.0369 | -0.1188 |
| 1933 | 0.5399 | 0.0312 | 0.5087 |
| 1934 | -0.0144 | 0.0318 | -0.0462 |
| 1935 | 0.4767 | 0.0281 | 0.4486 |
| 1936 | 0.3392 | 0.0277 | 0.3115 |
| 1937 | -0.3503 | 0.0266 | -0.3769 |
| 1938 | 0.3112 | 0.0264 | 0.2848 |
| 1939 | -0.0041 | 0.0240 | -0.0281 |
| 1940 | -0.0978 | 0.0223 | -0.1201 |
| 1941 | -0.1159 | 0.0194 | -0.1353 |
| 1942 | 0.2034 | 0.0246 | 0.1788 |
| 1943 | 0.2590 | 0.0244 | 0.2346 |
| 1944 | 0.1975 | 0.0246 | 0.1729 |
| 1945 | 0.3644 | 0.0234 | 0.3410 |
| 1946 | -0.0807 | 0.0204 | -0.1011 |
| 1947 | 0.0571 | 0.0213 | 0.0358 |
| 1948 | 0.0550 | 0.0240 | 0.0310 |
| 1949 | 0.1879 | 0.0225 | 0.1654 |
| 1950 | 0.3171 | 0.0212 | 0.2959 |
| 1951 | 0.2402 | 0.0238 | 0.2164 |
| 1952 | 0.1837 | 0.0266 | 0.1571 |
| 1953 | -0.0099 | 0.0284 | -0.0383 |
| 1954 | 0.5262 | 0.0279 | 0.4983 |
| 1955 | 0.3156 | 0.0275 | 0.2881 |
| 1956 | 0.0656 | 0.0299 | 0.0357 |
| 1957 | -0.1078 | 0.0344 | -0.1422 |
| 1958 | 0.4336 | 0.0327 | 0.4009 |
| 1959 | 0.1196 | 0.0401 | 0.0795 |
| 1960 | 0.0047 | 0.0426 | -0.0379 |
| 1961 | 0.2689 | 0.0383 | 0.2306 |
| 1962 | -0.0873 | 0.0400 | -0.1273 |
| 1963 | 0.2280 | 0.0389 | 0.1891 |
| 1964 | 0.1648 | 0.0415 | 0.1233 |
| 1965 | 0.1245 | 0.0419 | 0.0826 |
| 1966 | -0.1006 | 0.0449 | -0.1455 |
| 1967 | 0.2398 | 0.0459 | 0.1939 |
| 1968 | 0.1106 | 0.0550 | 0.0556 |
| 1969 | -0.0850 | 0.0595 | -0.1445 |
| 1970 | 0.0386 | 0.0674 | -0.0288 |
| 1971 | 0.1430 | 0.0632 | 0.0798 |
| 1972 | 0.1899 | 0.0587 | 0.1312 |
| 1973 | -0.1469 | 0.0651 | -0.2120 |
| 1974 | -0.2647 | 0.0727 | -0.3374 |
| 1975 | 0.3723 | 0.0799 | 0.2924 |
| 1976 | 0.2393 | 0.0789 | 0.1604 |
| 1977 | -0.0716 | 0.0714 | -0.1430 |
| 1978 | 0.0657 | 0.0790 | -0.0133 |
| 1979 | 0.1861 | 0.0886 | 0.0975 |
| 1980 | 0.3250 | 0.0997 | 0.2253 |
| 1981 | -0.0492 | 0.1155 | -0.1647 |
| 1982 | 0.2155 | 0.1350 | 0.0805 |
| 1983 | 0.2256 | 0.1038 | 0.1218 |
| 1984 | 0.0627 | 0.1174 | -0.0547 |
| 1985 | 0.3173 | 0.1125 | 0.2048 |
| 1986 | 0.1867 | 0.0898 | 0.0969 |
| 1987 | 0.0525 | 0.0792 | -0.0267 |
| 1988 | 0.1661 | 0.0897 | 0.0764 |
| 1989 | 0.3169 | 0.0881 | 0.2288 |
| 1990 | -0.0310 | 0.0819 | -0.1129 |
| 1991 | 0.3047 | 0.0822 | 0.2225 |
| 1992 | 0.0762 | 0.0726 | 0.0036 |
| 1993 | 0.1008 | 0.0717 | 0.0291 |
| 1994 | 0.0132 | 0.0659 | -0.0527 |
| 1995 | 0.3758 | 0.0760 | 0.2998 |
| 1996 | 0.2296 | 0.0618 | 0.1678 |
| 1997 | 0.3336 | 0.0664 | 0.2672 |
| 1998 | 0.2858 | 0.0583 | 0.2275 |
| 1999 | 0.2104 | 0.0557 | 0.1547 |
| 2000 | -0.0910 | 0.0650 | -0.1560 |
| 2001 | -0.1189 | 0.0553 | -0.1742 |
| 2002 | -0.2210 | 0.0559 | -0.2769 |
| 2003 | 0.2868 | 0.0480 | 0.2388 |
| 2004 | 0.1088 | 0.0502 | 0.0586 |
| 2005 | 0.0491 | 0.0469 | 0.0022 |
| 2006 | 0.1579 | 0.0468 | 0.1111 |
| 2007 | 0.0549 | 0.0486 | 0.0063 |
| 2008 | -0.3700 | 0.0445 | -0.4145 |
| 2009 | 0.2646 | 0.0347 | 0.2299 |
| 2010 | 0.1506 | 0.0425 | 0.1081 |
| 2011 | 0.0211 | 0.0382 | -0.0171 |
| 2012 | 0.1600 | 0.0246 | 0.1354 |
| 2013 | 0.3239 | 0.0288 | 0.2951 |
| 2014 | 0.1369 | 0.0341 | 0.1028 |
| 2015 | 0.0138 | 0.0247 | -0.0109 |
| 2016 | 0.1196 | 0.0230 | 0.0966 |
| 2017 | 0.2183 | 0.0267 | 0.1916 |
| 2018 | -0.0438 | 0.0282 | -0.0720 |
| 2019 | 0.3149 | 0.0255 | 0.2894 |
| Average | 0.1209 | 0.0494 | 0.0715 |
| Std. Dev. | 0.1976 | 0.0262 | 0.1987 |

Source: Duff & Phelps, 2020 SBBI Yearbook, Appendix A-1, A-7

**MRP**

| *Bin* | *Frequency* | *Cumulative %* |
|---|---|---|
| -50.00% | 0 | 0.0% |
| -47.50% | 0 | 0.0% |
| -45.00% | 1 | 1.1% |
| -42.50% | 0 | 1.1% |
| -40.00% | 1 | 2.1% |
| -37.50% | 1 | 3.2% |
| -35.00% | 0 | 3.2% |
| -32.50% | 1 | 4.3% |
| -30.00% | 0 | 4.3% |
| -27.50% | 2 | 6.4% |
| -25.00% | 0 | 6.4% |
| -22.50% | 0 | 6.4% |
| -20.00% | 1 | 7.4% |
| -17.50% | 0 | 7.4% |
| -15.00% | 3 | 10.6% |
| -12.50% | 6 | 17.0% |
| -10.00% | 5 | 22.3% |
| -7.50% | 0 | 22.3% |
| -5.00% | 3 | 25.5% |
| -2.50% | 6 | 31.9% |
| 0.00% | 3 | 35.1% |
| 2.50% | 3 | 38.3% |
| 5.00% | 4 | 42.6% |
| 7.50% | 2 | 44.7% |
| 10.00% | 9 | 54.3% |
| 12.50% | 5 | 59.6% |
| 15.00% | 2 | 61.7% |
| 17.50% | 6 | 68.1% |
| 20.00% | 4 | 72.3% |
| 22.50% | 3 | 75.5% |
| 25.00% | 7 | 83.0% |
| 27.50% | 1 | 84.0% |
| 30.00% | 7 | 91.5% |
| 32.50% | 1 | 92.6% |
| 35.00% | 2 | 94.7% |
| 37.50% | 0 | 94.7% |
| 40.00% | 0 | 94.7% |
| 42.50% | 2 | 96.8% |
| 45.00% | 1 | 97.9% |
| 47.50% | 0 | 97.9% |
| 50.00% | 1 | 98.9% |
| 51.00% | 1 | 100.0% |
| Count: | 94 | |

| Highest MRP from Direct | Rank | |
|---|---|---|
| 12.19% | 57.90% | 42.10% |

Historical Market Return from Direct

| D'Ascendis | % Rank | Occurrence |
|---|---|---|
| 14.48% | 50.70% | 46 |
| 14.62% | 50.90% | 46 |
| | | 94 |

CAPM vs. ECAPM Security Market Line
Using Mr. Baudino's Inputs

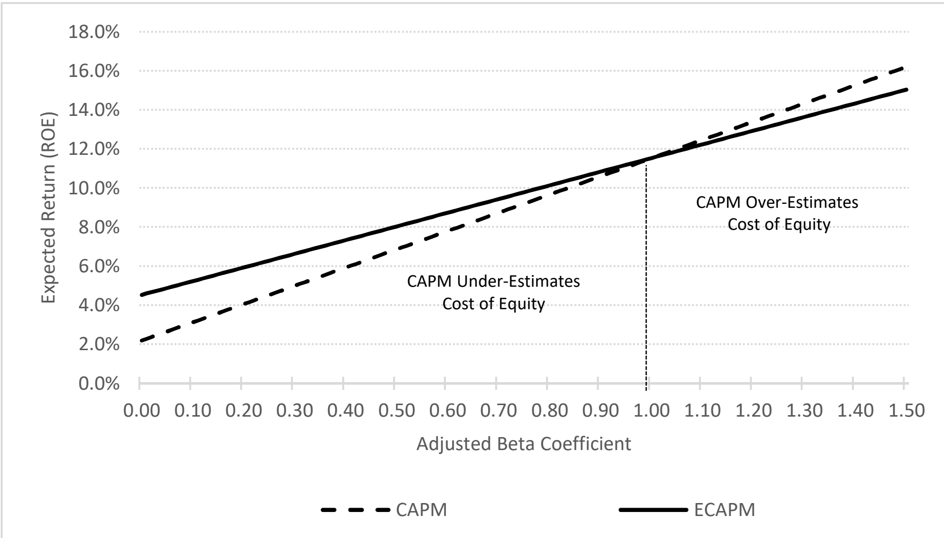
| | | | | |
|---|---|---|---|---|
| Risk-Free Rate | 2.19% | | ECAPM | 0.25 |
| MRP | 9.34% | | Factors | 0.75 |

| | | | ECAPM alpha | |
|---|---|---|---|---|
| | CAPM | ECAPM | 1.00% | 2.00% |
| 0.00 | 2.19% | 4.53% | 3.19% | 4.19% |
| 0.01 | 2.28% | 4.60% | 3.27% | 4.26% |
| 0.02 | 2.38% | 4.67% | 3.36% | 4.34% |
| 0.03 | 2.47% | 4.74% | 3.44% | 4.41% |
| 0.04 | 2.56% | 4.81% | 3.52% | 4.48% |
| 0.05 | 2.66% | 4.88% | 3.61% | 4.56% |
| 0.06 | 2.75% | 4.95% | 3.69% | 4.63% |
| 0.07 | 2.84% | 5.02% | 3.77% | 4.70% |
| 0.08 | 2.94% | 5.09% | 3.86% | 4.78% |
| 0.09 | 3.03% | 5.16% | 3.94% | 4.85% |
| 0.10 | 3.12% | 5.23% | 4.02% | 4.92% |
| 0.11 | 3.22% | 5.30% | 4.11% | 5.00% |
| 0.12 | 3.31% | 5.37% | 4.19% | 5.07% |
| 0.13 | 3.40% | 5.44% | 4.27% | 5.14% |
| 0.14 | 3.50% | 5.51% | 4.36% | 5.22% |
| 0.15 | 3.59% | 5.58% | 4.44% | 5.29% |
| 0.16 | 3.68% | 5.65% | 4.52% | 5.36% |
| 0.17 | 3.78% | 5.72% | 4.61% | 5.44% |
| 0.18 | 3.87% | 5.79% | 4.69% | 5.51% |
| 0.19 | 3.96% | 5.86% | 4.77% | 5.58% |
| 0.20 | 4.06% | 5.93% | 4.86% | 5.66% |
| 0.21 | 4.15% | 6.00% | 4.94% | 5.73% |
| 0.22 | 4.24% | 6.07% | 5.02% | 5.80% |
| 0.23 | 4.34% | 6.14% | 5.11% | 5.88% |
| 0.24 | 4.43% | 6.21% | 5.19% | 5.95% |
| 0.25 | 4.53% | 6.28% | 5.28% | 6.03% |
| 0.26 | 4.62% | 6.35% | 5.36% | 6.10% |
| 0.27 | 4.71% | 6.42% | 5.44% | 6.17% |
| 0.28 | 4.81% | 6.49% | 5.53% | 6.25% |
| 0.29 | 4.90% | 6.56% | 5.61% | 6.32% |
| 0.30 | 4.99% | 6.63% | 5.69% | 6.39% |
| 0.31 | 5.09% | 6.70% | 5.78% | 6.47% |
| 0.32 | 5.18% | 6.77% | 5.86% | 6.54% |
| 0.33 | 5.27% | 6.84% | 5.94% | 6.61% |
| 0.34 | 5.37% | 6.91% | 6.03% | 6.69% |
| 0.35 | 5.46% | 6.98% | 6.11% | 6.76% |
| 0.36 | 5.55% | 7.05% | 6.19% | 6.83% |
| 0.37 | 5.65% | 7.12% | 6.28% | 6.91% |
| 0.38 | 5.74% | 7.19% | 6.36% | 6.98% |
| 0.39 | 5.83% | 7.26% | 6.44% | 7.05% |
| 0.40 | 5.93% | 7.33% | 6.53% | 7.13% |
| 0.41 | 6.02% | 7.40% | 6.61% | 7.20% |
| 0.42 | 6.11% | 7.47% | 6.69% | 7.27% |
| 0.43 | 6.21% | 7.54% | 6.78% | 7.35% |
| 0.44 | 6.30% | 7.61% | 6.86% | 7.42% |
| 0.45 | 6.39% | 7.68% | 6.94% | 7.49% |
| 0.46 | 6.49% | 7.75% | 7.03% | 7.57% |
| 0.47 | 6.58% | 7.82% | 7.11% | 7.64% |

| | CAPM | ECAPM | 1.00% | 2.00% |
|---|---|---|---|---|
| 0.48 | 6.67% | 7.89% | 7.19% | 7.71% |
| 0.49 | 6.77% | 7.96% | 7.28% | 7.79% |
| 0.50 | 6.86% | 8.03% | 7.36% | 7.86% |
| 0.51 | 6.95% | 8.10% | 7.44% | 7.93% |
| 0.52 | 7.05% | 8.17% | 7.53% | 8.01% |
| 0.53 | 7.14% | 8.24% | 7.61% | 8.08% |
| 0.54 | 7.23% | 8.31% | 7.69% | 8.15% |
| 0.55 | 7.33% | 8.38% | 7.78% | 8.23% |
| 0.56 | 7.42% | 8.45% | 7.86% | 8.30% |
| 0.57 | 7.51% | 8.52% | 7.94% | 8.37% |
| 0.58 | 7.61% | 8.59% | 8.03% | 8.45% |
| 0.59 | 7.70% | 8.66% | 8.11% | 8.52% |
| 0.60 | 7.79% | 8.73% | 8.19% | 8.59% |
| 0.61 | 7.89% | 8.80% | 8.28% | 8.67% |
| 0.62 | 7.98% | 8.87% | 8.36% | 8.74% |
| 0.63 | 8.07% | 8.94% | 8.44% | 8.81% |
| 0.64 | 8.17% | 9.01% | 8.53% | 8.89% |
| 0.65 | 8.26% | 9.08% | 8.61% | 8.96% |
| 0.66 | 8.35% | 9.15% | 8.69% | 9.03% |
| 0.67 | 8.45% | 9.22% | 8.78% | 9.11% |
| 0.68 | 8.54% | 9.29% | 8.86% | 9.18% |
| 0.69 | 8.63% | 9.36% | 8.94% | 9.25% |
| 0.70 | 8.73% | 9.43% | 9.03% | 9.33% |
| 0.71 | 8.82% | 9.50% | 9.11% | 9.40% |
| 0.72 | 8.91% | 9.57% | 9.19% | 9.47% |
| 0.73 | 9.01% | 9.64% | 9.28% | 9.55% |
| 0.74 | 9.10% | 9.71% | 9.36% | 9.62% |
| 0.75 | 9.20% | 9.78% | 9.45% | 9.70% |
| 0.76 | 9.29% | 9.85% | 9.53% | 9.77% |
| 0.77 | 9.38% | 9.92% | 9.61% | 9.84% |
| 0.78 | 9.48% | 9.99% | 9.70% | 9.92% |
| 0.79 | 9.57% | 10.06% | 9.78% | 9.99% |
| 0.80 | 9.66% | 10.13% | 9.86% | 10.06% |
| 0.81 | 9.76% | 10.20% | 9.95% | 10.14% |
| 0.82 | 9.85% | 10.27% | 10.03% | 10.21% |
| 0.83 | 9.94% | 10.34% | 10.11% | 10.28% |
| 0.84 | 10.04% | 10.41% | 10.20% | 10.36% |
| 0.85 | 10.13% | 10.48% | 10.28% | 10.43% |
| 0.86 | 10.22% | 10.55% | 10.36% | 10.50% |
| 0.87 | 10.32% | 10.62% | 10.45% | 10.58% |
| 0.88 | 10.41% | 10.69% | 10.53% | 10.65% |
| 0.89 | 10.50% | 10.76% | 10.61% | 10.72% |
| 0.90 | 10.60% | 10.83% | 10.70% | 10.80% |
| 0.91 | 10.69% | 10.90% | 10.78% | 10.87% |
| 0.92 | 10.78% | 10.97% | 10.86% | 10.94% |
| 0.93 | 10.88% | 11.04% | 10.95% | 11.02% |
| 0.94 | 10.97% | 11.11% | 11.03% | 11.09% |
| 0.95 | 11.06% | 11.18% | 11.11% | 11.16% |
| 0.96 | 11.16% | 11.25% | 11.20% | 11.24% |
| 0.97 | 11.25% | 11.32% | 11.28% | 11.31% |
| 0.98 | 11.34% | 11.39% | 11.36% | 11.38% |
| 0.99 | 11.44% | 11.46% | 11.45% | 11.46% |
| 1.00 | 11.53% | 11.53% | 11.53% | 11.53% |
| 1.01 | 11.62% | 11.60% | 11.61% | 11.60% |

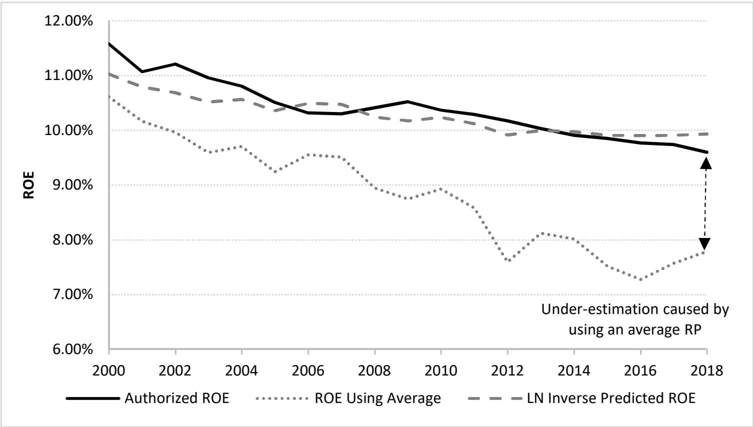
| | CAPM | ECAPM | 1.00% | 2.00% |
|---|---|---|---|---|
| 1.02 | 11.72% | 11.67% | 11.70% | 11.68% |
| 1.03 | 11.81% | 11.74% | 11.78% | 11.75% |
| 1.04 | 11.90% | 11.81% | 11.86% | 11.82% |
| 1.05 | 12.00% | 11.88% | 11.95% | 11.90% |
| 1.06 | 12.09% | 11.95% | 12.03% | 11.97% |
| 1.07 | 12.18% | 12.02% | 12.11% | 12.04% |
| 1.08 | 12.28% | 12.09% | 12.20% | 12.12% |
| 1.09 | 12.37% | 12.16% | 12.28% | 12.19% |
| 1.10 | 12.46% | 12.23% | 12.36% | 12.26% |
| 1.11 | 12.56% | 12.30% | 12.45% | 12.34% |
| 1.12 | 12.65% | 12.37% | 12.53% | 12.41% |
| 1.13 | 12.74% | 12.44% | 12.61% | 12.48% |
| 1.14 | 12.84% | 12.51% | 12.70% | 12.56% |
| 1.15 | 12.93% | 12.58% | 12.78% | 12.63% |
| 1.16 | 13.02% | 12.65% | 12.86% | 12.70% |
| 1.17 | 13.12% | 12.72% | 12.95% | 12.78% |
| 1.18 | 13.21% | 12.79% | 13.03% | 12.85% |
| 1.19 | 13.30% | 12.86% | 13.11% | 12.92% |
| 1.20 | 13.40% | 12.93% | 13.20% | 13.00% |
| 1.21 | 13.49% | 13.00% | 13.28% | 13.07% |
| 1.22 | 13.58% | 13.07% | 13.36% | 13.14% |
| 1.23 | 13.68% | 13.14% | 13.45% | 13.22% |
| 1.24 | 13.77% | 13.21% | 13.53% | 13.29% |
| 1.25 | 13.87% | 13.28% | 13.62% | 13.37% |
| 1.26 | 13.96% | 13.35% | 13.70% | 13.44% |
| 1.27 | 14.05% | 13.42% | 13.78% | 13.51% |
| 1.28 | 14.15% | 13.49% | 13.87% | 13.59% |
| 1.29 | 14.24% | 13.56% | 13.95% | 13.66% |
| 1.30 | 14.33% | 13.63% | 14.03% | 13.73% |
| 1.31 | 14.43% | 13.70% | 14.12% | 13.81% |
| 1.32 | 14.52% | 13.77% | 14.20% | 13.88% |
| 1.33 | 14.61% | 13.84% | 14.28% | 13.95% |
| 1.34 | 14.71% | 13.91% | 14.37% | 14.03% |
| 1.35 | 14.80% | 13.98% | 14.45% | 14.10% |
| 1.36 | 14.89% | 14.05% | 14.53% | 14.17% |
| 1.37 | 14.99% | 14.12% | 14.62% | 14.25% |
| 1.38 | 15.08% | 14.19% | 14.70% | 14.32% |
| 1.39 | 15.17% | 14.26% | 14.78% | 14.39% |
| 1.40 | 15.27% | 14.33% | 14.87% | 14.47% |
| 1.41 | 15.36% | 14.40% | 14.95% | 14.54% |
| 1.42 | 15.45% | 14.47% | 15.03% | 14.61% |
| 1.43 | 15.55% | 14.54% | 15.12% | 14.69% |
| 1.44 | 15.64% | 14.61% | 15.20% | 14.76% |
| 1.45 | 15.73% | 14.68% | 15.28% | 14.83% |
| 1.46 | 15.83% | 14.75% | 15.37% | 14.91% |
| 1.47 | 15.92% | 14.82% | 15.45% | 14.98% |
| 1.48 | 16.01% | 14.89% | 15.53% | 15.05% |
| 1.49 | 16.11% | 14.96% | 15.62% | 15.13% |
| 1.50 | 16.20% | 15.03% | 15.70% | 15.20% |

Source: Exhibit RAB-4


18.0%
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
Expected Return (ROE)
0.00 0.10 0.20 0.30 0.40 0.50 0.60 0.70 0.80 0.90 1.00 1.10 1.20 1.30 1.40 1.50
Adjusted Beta Coefficient
CAPM Over-Estimates Cost of Equity
CAPM Under-Estimates Cost of Equity
CAPM
ECAPM

Relative Accuracy of Average Equity Risk Premiums and Predicted Risk Premiums

| Rate Case Year | Auth. ROE [1] | Avg 30-Yr Treasury [2] | Average RP [3] | ROE Using Average | Error | LN Inverse Predicted RP [4] | LN Inverse Predicted ROE | Error |
|---|---|---|---|---|---|---|---|---|
| 2000 | 11.58% | 5.93% | 4.68% | 10.61% | -0.97% | 5.09% | 11.03% | -0.55% |
| 2001 | 11.07% | 5.49% | 4.68% | 10.17% | -0.90% | 5.30% | 10.79% | -0.28% |
| 2002 | 11.21% | 5.28% | 4.68% | 9.96% | -1.25% | 5.40% | 10.69% | -0.52% |
| 2003 | 10.96% | 4.92% | 4.68% | 9.60% | -1.36% | 5.59% | 10.51% | -0.45% |
| 2004 | 10.81% | 5.03% | 4.68% | 9.70% | -1.11% | 5.54% | 10.56% | -0.25% |
| 2005 | 10.51% | 4.57% | 4.68% | 9.24% | -1.27% | 5.79% | 10.36% | -0.15% |
| 2006 | 10.32% | 4.88% | 4.68% | 9.55% | -0.77% | 5.62% | 10.49% | 0.17% |
| 2007 | 10.30% | 4.84% | 4.68% | 9.51% | -0.79% | 5.64% | 10.48% | 0.18% |
| 2008 | 10.41% | 4.27% | 4.68% | 8.94% | -1.47% | 5.98% | 10.24% | -0.17% |
| 2009 | 10.52% | 4.07% | 4.68% | 8.75% | -1.77% | 6.10% | 10.17% | -0.35% |
| 2010 | 10.37% | 4.25% | 4.68% | 8.92% | -1.45% | 5.99% | 10.24% | -0.13% |
| 2011 | 10.29% | 3.90% | 4.68% | 8.58% | -1.71% | 6.21% | 10.12% | -0.17% |
| 2012 | 10.17% | 2.92% | 4.68% | 7.59% | -2.58% | 6.99% | 9.91% | -0.26% |
| 2013 | 10.03% | 3.45% | 4.68% | 8.12% | -1.91% | 6.55% | 9.99% | -0.04% |
| 2014 | 9.91% | 3.34% | 4.68% | 8.01% | -1.90% | 6.63% | 9.97% | 0.06% |
| 2015 | 9.85% | 2.84% | 4.68% | 7.52% | -2.33% | 7.06% | 9.91% | 0.06% |
| 2016 | 9.77% | 2.60% | 4.68% | 7.27% | -2.50% | 7.30% | 9.90% | 0.13% |
| 2017 | 9.74% | 2.89% | 4.68% | 7.57% | -2.17% | 7.02% | 9.91% | 0.17% |
| 2018 | 9.60% | 3.11% | 4.68% | 7.79% | -1.81% | 6.82% | 9.93% | 0.33% |
| 2019 | 9.65% | 2.58% | 4.68% | 7.25% | -2.40% | 7.32% | 9.90% | 0.25% |
| Average: | 10.35% | 4.06% | 4.68% | 8.73% | -1.62% | 6.20% | 10.26% | -0.10% |




Stdev: 0.26%

Notes
[1] Source: Regulatory Research Associates: Regulatory Focus, Major Rate Case Decisions January - December 2019, January 31, 2020; all electric rate cases
[2] Source: Bloomberg Professional
[3] Source: Exhibit DWD-5
[4] Source: Exhibit DWD-5 (regression coefficients)

Retention Ratio Regression Analysis - Mr. O'Donnell's Proxy Group

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.33588834 |
| R Square | 0.112820977 |
| Adjusted R Square | 0.110614064 |
| Standard Error | 0.187578324 |
| Observations | 404 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 1 | 1.798746443 | 1.798746443 | 51.12162426 | 4.12617E-12 |
| Residual | 402 | 14.14462237 | 0.035185628 | | |
| Total | 403 | 15.94336882 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | 0.108 | 0.012 | 9.201 | 0.000 | 0.085 | 0.131 |
| Retention Ratio | -0.166 | 0.023 | -7.150 | 0.000 | -0.211 | -0.120 |

Source: Value Line

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2004 | ALE | 22.22% | 77.78% | 13.03% |
| 2005 | ALE | 50.40% | 49.60% | -0.53% |
| 2006 | ALE | 52.35% | 47.65% | 1.33% |
| 2007 | ALE | 53.25% | 46.75% | -1.44% |
| 2008 | ALE | 60.99% | 39.01% | 0.64% |
| 2009 | ALE | 93.12% | 6.88% | 9.29% |
| 2010 | ALE | 80.37% | 19.63% | 9.42% |
| 2011 | ALE | 67.17% | 32.83% | 3.80% |
| 2012 | ALE | 71.32% | 28.68% | 4.27% |
| 2013 | ALE | 72.24% | 27.76% | 5.48% |
| 1996 | LNT | 86.78% | 13.22% | 6.92% |
| 1997 | LNT | 105.26% | -5.26% | -0.07% |
| 1998 | LNT | 158.73% | -58.73% | 13.28% |
| 1999 | LNT | 91.32% | 8.68% | 2.08% |
| 2000 | LNT | 80.97% | 19.03% | 3.42% |
| 2001 | LNT | 82.64% | 17.36% | 2.46% |
| 2002 | LNT | 169.49% | -69.49% | 18.83% |
| 2003 | LNT | 63.69% | 36.31% | 11.10% |
| 2004 | LNT | 55.14% | 44.86% | 2.50% |
| 2005 | LNT | 47.51% | 52.49% | 7.55% |
| 2006 | LNT | 55.83% | 44.17% | 8.91% |
| 2007 | LNT | 47.21% | 52.79% | 4.97% |
| 2008 | LNT | 55.12% | 44.88% | 7.73% |
| 2009 | LNT | 78.95% | 21.05% | 13.86% |
| 2010 | LNT | 57.45% | 42.55% | 4.34% |
| 2011 | LNT | 61.82% | 38.18% | 3.86% |
| 2012 | LNT | 59.02% | 40.98% | 5.80% |
| 2013 | LNT | 56.97% | 43.03% | 6.17% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1996 | AEE | 87.76% | 12.24% | 4.29% |
| 1997 | AEE | 104.10% | -4.10% | 2.83% |
| 1998 | AEE | 90.07% | 9.93% | 3.32% |
| 1999 | AEE | 90.39% | 9.61% | 1.35% |
| 2000 | AEE | 76.28% | 23.72% | -0.15% |
| 2001 | AEE | 74.49% | 25.51% | -3.63% |
| 2002 | AEE | 95.49% | 4.51% | 3.17% |
| 2003 | AEE | 80.89% | 19.11% | -1.11% |
| 2004 | AEE | 90.07% | 9.93% | 0.24% |
| 2005 | AEE | 81.15% | 18.85% | -2.03% |
| 2006 | AEE | 95.49% | 4.51% | -1.20% |
| 2007 | AEE | 85.23% | 14.77% | -4.09% |
| 2008 | AEE | 88.19% | 11.81% | -5.99% |
| 2009 | AEE | 55.40% | 44.60% | -2.44% |
| 2010 | AEE | 55.60% | 44.40% | -2.53% |
| 2011 | AEE | 63.16% | 36.84% | 2.15% |
| 2012 | AEE | 66.39% | 33.61% | 3.31% |
| 2013 | AEE | 76.19% | 23.81% | 9.85% |
| 1996 | AEP | 76.43% | 23.57% | 27.79% |
| 1997 | AEP | 73.17% | 26.83% | 24.39% |
| 1998 | AEP | 85.41% | 14.59% | 24.95% |
| 1999 | AEP | 89.22% | 10.78% | 26.43% |
| 2000 | AEP | 230.77% | -130.77% | 38.93% |
| 2001 | AEP | 73.39% | 26.61% | -2.29% |
| 2002 | AEP | 83.92% | 16.08% | 0.22% |
| 2003 | AEP | 65.22% | 34.78% | 3.44% |
| 2004 | AEP | 53.64% | 46.36% | 2.67% |
| 2005 | AEP | 53.79% | 46.21% | -0.05% |
| 2006 | AEP | 52.45% | 47.55% | 2.36% |
| 2007 | AEP | 55.24% | 44.76% | 1.40% |
| 2008 | AEP | 54.85% | 45.15% | 1.84% |
| 2009 | AEP | 55.22% | 44.78% | 2.98% |
| 2010 | AEP | 65.77% | 34.23% | 6.96% |
| 2011 | AEP | 59.11% | 40.89% | 6.45% |
| 2012 | AEP | 63.09% | 36.91% | 4.53% |
| 2013 | AEP | 61.32% | 38.68% | 4.73% |
| 1996 | CMS | 41.63% | 58.37% | -8.29% |
| 1997 | CMS | 43.68% | 56.32% | -76.68% |
| 1998 | CMS | 56.25% | 43.75% | -91.91% |
| 1999 | CMS | 48.77% | 51.23% | -168.39% |
| 2000 | CMS | 57.71% | 42.29% | -156.41% |
| 2001 | CMS | 114.96% | -14.96% | -154.82% |
| 2007 | CMS | 31.25% | 68.75% | 25.07% |
| 2008 | CMS | 29.27% | 70.73% | 8.33% |
| 2009 | CMS | 53.76% | 46.24% | 14.17% |
| 2010 | CMS | 49.62% | 50.38% | 7.30% |
| 2011 | CMS | 57.93% | 42.07% | 6.44% |
| 2012 | CMS | 62.75% | 37.25% | 7.26% |
| 2013 | CMS | 61.45% | 38.55% | 6.94% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1997 | ED | 71.19% | 28.81% | 1.64% |
| 1998 | ED | 69.74% | 30.26% | -0.88% |
| 1999 | ED | 68.37% | 31.63% | -5.08% |
| 2000 | ED | 79.56% | 20.44% | 3.19% |
| 2001 | ED | 68.54% | 31.46% | -0.51% |
| 2002 | ED | 70.93% | 29.07% | 3.58% |
| 2003 | ED | 79.15% | 20.85% | 4.81% |
| 2004 | ED | 97.41% | 2.59% | 7.10% |
| 2005 | ED | 76.25% | 23.75% | 3.43% |
| 2006 | ED | 77.97% | 22.03% | 4.27% |
| 2007 | ED | 66.67% | 33.33% | 2.30% |
| 2008 | ED | 69.64% | 30.36% | 3.36% |
| 2009 | ED | 75.16% | 24.84% | 3.09% |
| 2010 | ED | 68.59% | 31.41% | 3.36% |
| 2011 | ED | 67.23% | 32.77% | 2.24% |
| 2012 | ED | 62.69% | 37.31% | 1.43% |
| 2013 | ED | 62.60% | 37.40% | 3.26% |
| 1997 | D | 86.00% | 14.00% | 19.21% |
| 1998 | D | 150.00% | -50.00% | 24.00% |
| 1999 | D | 86.00% | 14.00% | 10.86% |
| 2000 | D | 103.20% | -3.20% | 8.27% |
| 2001 | D | 86.58% | 13.42% | 16.43% |
| 2002 | D | 53.53% | 46.47% | 1.83% |
| 2003 | D | 65.82% | 34.18% | 14.11% |
| 2004 | D | 61.03% | 38.97% | 9.75% |
| 2005 | D | 89.33% | 10.67% | 17.56% |
| 2006 | D | 57.50% | 42.50% | 4.66% |
| 2007 | D | 68.54% | 31.46% | 6.83% |
| 2008 | D | 51.97% | 48.03% | 0.76% |
| 2009 | D | 66.29% | 33.71% | 3.14% |
| 2010 | D | 63.32% | 36.68% | 2.23% |
| 2011 | D | 71.38% | 28.62% | 4.62% |
| 2012 | D | 76.73% | 23.27% | 5.22% |
| 2013 | D | 72.82% | 27.18% | 1.16% |
| 2007 | DUK | 71.67% | 28.33% | 1.45% |
| 2008 | DUK | 89.11% | 10.89% | 6.07% |
| 2009 | DUK | 83.19% | 16.81% | 4.45% |
| 2010 | DUK | 72.39% | 27.61% | 0.58% |
| 2011 | DUK | 71.74% | 28.26% | -1.92% |
| 2012 | DUK | 81.67% | 18.33% | 2.91% |
| 2013 | DUK | 77.64% | 22.36% | 1.03% |
| 2004 | EIX | 115.94% | -15.94% | 76.47% |
| 2005 | EIX | 30.54% | 69.46% | 0.34% |
| 2006 | EIX | 33.54% | 66.46% | -0.02% |
| 2007 | EIX | 35.54% | 64.46% | 7.91% |
| 2008 | EIX | 33.42% | 66.58% | 2.36% |
| 2009 | EIX | 38.58% | 61.42% | 7.66% |
| 2010 | EIX | 37.91% | 62.09% | 6.15% |
| 2011 | EIX | 39.94% | 60.06% | 5.86% |
| 2012 | EIX | 28.79% | 71.21% | 0.58% |
| 2013 | EIX | 36.24% | 63.76% | -21.63% |
| 1997 | ETR | 80.00% | 20.00% | 11.04% |
| 1998 | ETR | 67.57% | 32.43% | 11.36% |
| 1999 | ETR | 53.33% | 46.67% | 12.39% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2000 | ETR | 41.08% | 58.92% | 8.38% |
| 2001 | ETR | 41.56% | 58.44% | 12.01% |
| 2002 | ETR | 36.41% | 63.59% | 9.01% |
| 2003 | ETR | 43.36% | 56.64% | 11.09% |
| 2004 | ETR | 48.09% | 51.91% | 10.12% |
| 2005 | ETR | 49.09% | 50.91% | 8.87% |
| 2006 | ETR | 40.30% | 59.70% | 7.18% |
| 2007 | ETR | 46.07% | 53.93% | 2.23% |
| 2008 | ETR | 48.39% | 51.61% | -3.44% |
| 2009 | ETR | 47.62% | 52.38% | -0.49% |
| 2010 | ETR | 48.65% | 51.35% | -1.50% |
| 2011 | ETR | 43.97% | 56.03% | -0.49% |
| 2012 | ETR | 55.15% | 44.85% | -1.35% |
| 2013 | ETR | 66.94% | 33.06% | 4.83% |
| 2001 | ES | 32.85% | 67.15% | -8.32% |
| 2002 | ES | 49.07% | 50.93% | 14.69% |
| 2003 | ES | 46.77% | 53.23% | 15.13% |
| 2004 | ES | 69.23% | 30.77% | 20.99% |
| 2005 | ES | 69.39% | 30.61% | 21.44% |
| 2006 | ES | 89.02% | 10.98% | 25.85% |
| 2007 | ES | 49.06% | 50.94% | 4.09% |
| 2008 | ES | 44.62% | 55.38% | 7.05% |
| 2009 | ES | 49.74% | 50.26% | 7.23% |
| 2010 | ES | 49.05% | 50.95% | 6.64% |
| 2011 | ES | 49.55% | 50.45% | 6.94% |
| 2012 | ES | 69.84% | 30.16% | 10.93% |
| 2013 | ES | 59.04% | 40.96% | 5.48% |
| 1996 | HE | 93.08% | 6.92% | 4.99% |
| 1997 | HE | 88.41% | 11.59% | 4.01% |
| 1998 | HE | 83.78% | 16.22% | 2.06% |
| 1999 | HE | 85.52% | 14.48% | -0.31% |
| 2000 | HE | 97.64% | 2.36% | 3.64% |
| 2001 | HE | 77.50% | 22.50% | -3.34% |
| 2002 | HE | 76.54% | 23.46% | -6.90% |
| 2003 | HE | 78.48% | 21.52% | -7.12% |
| 2004 | HE | 91.18% | 8.82% | -7.33% |
| 2005 | HE | 84.93% | 15.07% | -2.21% |
| 2006 | HE | 93.23% | 6.77% | 3.38% |
| 2007 | HE | 111.71% | -11.71% | 9.88% |
| 2008 | HE | 115.89% | -15.89% | 10.00% |
| 2009 | HE | 136.26% | -36.26% | 13.24% |
| 2010 | HE | 102.48% | -2.48% | 4.94% |
| 2011 | HE | 86.11% | 13.89% | 11.67% |
| 2012 | HE | 74.25% | 25.75% | 2.80% |
| 2013 | HE | 76.54% | 23.46% | 5.96% |
| 1996 | IDA | 84.16% | 15.84% | 9.88% |
| 1997 | IDA | 80.17% | 19.83% | -1.38% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1998 | IDA | 78.48% | 21.52% | -10.03% |
| 1999 | IDA | 76.54% | 23.46% | 9.04% |
| 2000 | IDA | 53.14% | 46.86% | -1.34% |
| 2001 | IDA | 55.52% | 44.48% | 6.37% |
| 2002 | IDA | 114.11% | -14.11% | 12.47% |
| 2003 | IDA | 177.08% | -77.08% | 24.13% |
| 2004 | IDA | 63.16% | 36.84% | 8.77% |
| 2005 | IDA | 68.57% | 31.43% | 12.70% |
| 2006 | IDA | 51.06% | 48.94% | 8.62% |
| 2007 | IDA | 64.52% | 35.48% | 12.85% |
| 2008 | IDA | 55.05% | 44.95% | 11.01% |
| 2009 | IDA | 45.45% | 54.55% | 7.94% |
| 2010 | IDA | 40.68% | 59.32% | 5.70% |
| 2011 | IDA | 35.71% | 64.29% | 3.28% |
| 2012 | IDA | 40.65% | 59.35% | 4.59% |
| 2013 | IDA | 43.13% | 56.87% | 4.32% |
| 1998 | MGEE | 93.48% | 6.52% | 4.51% |
| 1999 | MGEE | 87.88% | 12.12% | 3.69% |
| 2000 | MGEE | 79.28% | 20.72% | -0.94% |
| 2001 | MGEE | 82.41% | 17.59% | 5.70% |
| 2002 | MGEE | 78.76% | 21.24% | 6.81% |
| 2003 | MGEE | 78.95% | 21.05% | 7.70% |
| 2004 | MGEE | 77.12% | 22.88% | 5.49% |
| 2005 | MGEE | 87.62% | 12.38% | 10.41% |
| 2006 | MGEE | 67.88% | 32.12% | 5.39% |
| 2007 | MGEE | 62.25% | 37.75% | 4.49% |
| 2008 | MGEE | 60.38% | 39.62% | 6.65% |
| 2009 | MGEE | 65.99% | 34.01% | 9.64% |
| 2010 | MGEE | 59.28% | 40.72% | 4.68% |
| 2011 | MGEE | 57.39% | 42.61% | 4.77% |
| 2012 | MGEE | 55.91% | 44.09% | 3.81% |
| 2013 | MGEE | 49.54% | 50.46% | 2.68% |
| 1996 | NEE | 55.26% | 44.74% | 6.82% |
| 1997 | NEE | 53.63% | 46.37% | 2.72% |
| 1998 | NEE | 51.81% | 48.19% | 5.53% |
| 1999 | NEE | 50.98% | 49.02% | 4.48% |
| 2000 | NEE | 52.17% | 47.83% | 3.04% |
| 2001 | NEE | 48.48% | 51.52% | 8.57% |
| 2002 | NEE | 57.71% | 42.29% | 11.41% |
| 2003 | NEE | 48.98% | 51.02% | 11.93% |
| 2004 | NEE | 52.85% | 47.15% | 11.36% |
| 2005 | NEE | 61.21% | 38.79% | 16.37% |
| 2006 | NEE | 46.44% | 53.56% | 8.87% |
| 2007 | NEE | 50.15% | 49.85% | 7.54% |
| 2008 | NEE | 43.73% | 56.27% | 3.83% |
| 2009 | NEE | 47.61% | 52.39% | 7.51% |
| 2010 | NEE | 42.19% | 57.81% | 5.27% |
| 2011 | NEE | 45.64% | 54.36% | 4.01% |
| 2012 | NEE | 52.63% | 47.37% | 7.58% |
| 2013 | NEE | 54.66% | 45.34% | 6.92% |
| 2005 | NWE | 58.48% | 41.52% | 5.90% |
| 2006 | NWE | 94.66% | 5.34% | 14.23% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2007 | NWE | 88.89% | 11.11% | 10.11% |
| 2008 | NWE | 74.58% | 25.42% | 7.29% |
| 2009 | NWE | 66.34% | 33.66% | 8.78% |
| 2010 | NWE | 63.55% | 36.45% | 6.99% |
| 2011 | NWE | 56.92% | 43.08% | 6.72% |
| 2012 | NWE | 65.49% | 34.51% | 8.56% |
| 2013 | NWE | 61.79% | 38.21% | 7.15% |
| 1998 | OGE | 65.69% | 34.31% | -1.39% |
| 1999 | OGE | 69.07% | 30.93% | 0.05% |
| 2000 | OGE | 70.53% | 29.47% | 1.14% |
| 2001 | OGE | 103.08% | -3.08% | 14.19% |
| 2002 | OGE | 93.06% | 6.94% | 13.50% |
| 2003 | OGE | 77.01% | 22.99% | 8.28% |
| 2004 | OGE | 75.28% | 24.72% | 9.10% |
| 2005 | OGE | 72.83% | 27.17% | 10.98% |
| 2006 | OGE | 54.47% | 45.53% | 7.31% |
| 2007 | OGE | 51.52% | 48.48% | 6.54% |
| 2008 | OGE | 56.00% | 44.00% | 9.27% |
| 2009 | OGE | 53.38% | 46.62% | 8.41% |
| 2010 | OGE | 48.67% | 51.33% | 2.92% |
| 2011 | OGE | 43.93% | 56.07% | -0.15% |
| 2012 | OGE | 44.69% | 55.31% | 1.88% |
| 2013 | OGE | 43.81% | 56.19% | 2.29% |
| 1996 | OTTR | 72.58% | 27.42% | 6.36% |
| 1997 | OTTR | 72.09% | 27.91% | 6.86% |
| 1998 | OTTR | 74.42% | 25.58% | 3.73% |
| 1999 | OTTR | 68.28% | 31.72% | 1.12% |
| 2000 | OTTR | 63.75% | 36.25% | 2.78% |
| 2001 | OTTR | 61.90% | 38.10% | 0.77% |
| 2002 | OTTR | 59.22% | 40.78% | 0.53% |
| 2003 | OTTR | 71.52% | 28.48% | -4.10% |
| 2004 | OTTR | 73.33% | 26.67% | -10.94% |
| 2005 | OTTR | 62.92% | 37.08% | -23.97% |
| 2006 | OTTR | 68.05% | 31.95% | -19.27% |
| 2007 | OTTR | 65.73% | 34.27% | 6.33% |
| 2008 | OTTR | 109.17% | -9.17% | 20.18% |
| 2009 | OTTR | 167.61% | -67.61% | 29.78% |
| 2010 | OTTR | 313.16% | -213.16% | 39.20% |
| 2011 | OTTR | 264.44% | -164.44% | 36.03% |
| 2012 | OTTR | 113.33% | -13.33% | 12.61% |
| 2013 | OTTR | 86.86% | 13.14% | 8.67% |
| 1996 | PNW | 41.70% | 58.30% | 8.36% |
| 1997 | PNW | 40.94% | 59.06% | -0.24% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1998 | PNW | 43.16% | 56.84% | -0.97% |
| 1999 | PNW | 41.82% | 58.18% | -2.81% |
| 2000 | PNW | 42.69% | 57.31% | -6.52% |
| 2001 | PNW | 41.58% | 58.42% | -0.18% |
| 2002 | PNW | 64.43% | 35.57% | 4.74% |
| 2003 | PNW | 68.65% | 31.35% | -0.86% |
| 2004 | PNW | 70.93% | 29.07% | -0.01% |
| 2005 | PNW | 86.16% | 13.84% | 9.88% |
| 2006 | PNW | 64.04% | 35.96% | 0.99% |
| 2007 | PNW | 70.95% | 29.05% | 5.73% |
| 2008 | PNW | 99.06% | 0.94% | 12.32% |
| 2009 | PNW | 92.92% | 7.08% | 10.56% |
| 2010 | PNW | 68.18% | 31.82% | 5.20% |
| 2011 | PNW | 70.23% | 29.77% | 5.94% |
| 2012 | PNW | 76.29% | 23.71% | 4.96% |
| 2013 | PNW | 60.93% | 39.07% | 4.54% |
| 1996 | PNM | 20.87% | 79.13% | 20.65% |
| 1997 | PNM | 33.60% | 66.40% | 7.11% |
| 1998 | PNM | 34.00% | 66.00% | 4.60% |
| 1999 | PNM | 41.09% | 58.91% | 12.27% |
| 2000 | PNM | 34.19% | 65.81% | 10.06% |
| 2001 | PNM | 20.31% | 79.69% | -1.57% |
| 2002 | PNM | 53.27% | 46.73% | -0.93% |
| 2003 | PNM | 53.04% | 46.96% | -19.53% |
| 2004 | PNM | 44.06% | 55.94% | 61.06% |
| 2005 | PNM | 50.64% | 49.36% | 69.24% |
| 2006 | PNM | 50.00% | 50.00% | 72.01% |
| 2007 | PNM | 119.74% | -19.74% | 87.44% |
| 2008 | PNM | 554.55% | -454.55% | 106.07% |
| 2009 | PNM | 86.21% | 13.79% | 21.18% |
| 2010 | PNM | 57.47% | 42.53% | 13.80% |
| 2011 | PNM | 46.30% | 53.70% | 9.10% |
| 2012 | PNM | 44.27% | 55.73% | 8.11% |
| 2013 | PNM | 48.23% | 51.77% | 3.87% |
| 2006 | POR | 59.65% | 40.35% | 20.49% |
| 2007 | POR | 39.91% | 60.09% | -1.20% |
| 2008 | POR | 69.78% | 30.22% | 5.80% |
| 2009 | POR | 77.10% | 22.90% | 11.58% |
| 2010 | POR | 62.65% | 37.35% | 4.95% |
| 2011 | POR | 54.36% | 45.64% | 2.63% |
| 2012 | POR | 57.75% | 42.25% | 4.66% |
| 2013 | POR | 62.15% | 37.85% | 6.43% |
| 1997 | PEG | 89.26% | 10.74% | 9.36% |
| 1998 | PEG | 77.14% | 22.86% | 6.22% |
| 1999 | PEG | 69.23% | 30.77% | 0.10% |
| 2000 | PEG | 60.67% | 39.33% | 0.83% |
| 2001 | PEG | 58.38% | 41.62% | 0.72% |
| 2002 | PEG | 57.45% | 42.55% | 8.39% |
| 2003 | PEG | 57.45% | 42.55% | 10.79% |
| 2004 | PEG | 72.37% | 27.63% | 15.86% |
| 2005 | PEG | 62.57% | 37.43% | 12.24% |
| 2006 | PEG | 61.62% | 38.38% | 11.83% |
| 2007 | PEG | 45.17% | 54.83% | -0.48% |
| 2008 | PEG | 44.48% | 55.52% | -2.79% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 2009 | PEG | 43.18% | 56.82% | 0.38% |
| 2010 | PEG | 44.63% | 55.37% | 2.52% |
| 2011 | PEG | 44.05% | 55.95% | -0.59% |
| 2012 | PEG | 58.20% | 41.80% | 3.64% |
| 2013 | PEG | 58.78% | 41.22% | 3.14% |
| 1996 | SRE | 78.79% | 21.21% | 9.85% |
| 1997 | SRE | 70.91% | 29.09% | 9.51% |
| 1998 | SRE | 125.81% | -25.81% | 19.81% |
| 1999 | SRE | 93.98% | 6.02% | 19.15% |
| 2000 | SRE | 48.54% | 51.46% | 12.24% |
| 2001 | SRE | 39.22% | 60.78% | 11.52% |
| 2002 | SRE | 35.84% | 64.16% | 9.78% |
| 2003 | SRE | 33.22% | 66.78% | 9.00% |
| 2004 | SRE | 25.45% | 74.55% | 4.47% |
| 2005 | SRE | 32.95% | 67.05% | 3.37% |
| 2006 | SRE | 28.37% | 71.63% | 1.58% |
| 2007 | SRE | 29.11% | 70.89% | 0.90% |
| 2008 | SRE | 30.93% | 69.07% | -0.50% |
| 2009 | SRE | 32.64% | 67.36% | -0.13% |
| 2010 | SRE | 38.81% | 61.19% | 5.64% |
| 2011 | SRE | 42.95% | 57.05% | -0.39% |
| 2012 | SRE | 55.17% | 44.83% | 1.99% |
| 2013 | SRE | 59.72% | 40.28% | 6.26% |
| 1996 | SO | 75.00% | 25.00% | -0.15% |
| 1997 | SO | 82.28% | 17.72% | 4.02% |
| 1998 | SO | 77.46% | 22.54% | 3.42% |
| 1999 | SO | 73.22% | 26.78% | 3.18% |
| 2000 | SO | 66.67% | 33.33% | 1.89% |
| 2001 | SO | 83.23% | 16.77% | 5.59% |
| 2002 | SO | 73.51% | 26.49% | 4.32% |
| 2003 | SO | 70.56% | 29.44% | 2.76% |
| 2004 | SO | 68.93% | 31.07% | 2.47% |
| 2005 | SO | 69.48% | 30.52% | 2.14% |
| 2006 | SO | 73.33% | 26.67% | 4.03% |
| 2007 | SO | 70.18% | 29.82% | 3.26% |
| 2008 | SO | 73.78% | 26.22% | 3.74% |
| 2009 | SO | 74.57% | 25.43% | 3.64% |
| 2010 | SO | 76.27% | 23.73% | 3.80% |
| 2011 | SO | 73.33% | 26.67% | 2.12% |
| 2012 | SO | 72.66% | 27.34% | 3.86% |
| 2013 | SO | 74.44% | 25.56% | 2.33% |
| 1996 | WEC | 75.76% | 24.24% | 35.15% |
| 1997 | WEC | 285.19% | -185.19% | 54.91% |

| Date | Ticker | Payout Ratio | Retention Ratio | 5-year Fwd EPS Growth |
|---|---|---|---|---|
| 1998 | WEC | 93.98% | 6.02% | 12.91% |
| 1999 | WEC | 82.98% | 17.02% | 6.72% |
| 2000 | WEC | 127.78% | -27.78% | 22.76% |
| 2001 | WEC | 43.48% | 56.52% | 9.31% |
| 2002 | WEC | 34.48% | 65.52% | 5.61% |
| 2003 | WEC | 35.40% | 64.60% | 7.54% |
| 2004 | WEC | 45.16% | 54.84% | 12.13% |
| 2005 | WEC | 34.38% | 65.63% | 8.60% |
| 2006 | WEC | 34.85% | 65.15% | 10.68% |
| 2007 | WEC | 35.21% | 64.79% | 10.73% |
| 2008 | WEC | 35.53% | 64.47% | 10.68% |
| 2009 | WEC | 42.50% | 57.50% | 10.27% |
| 2010 | WEC | 41.67% | 58.33% | 4.34% |
| 2011 | WEC | 47.71% | 52.29% | 6.93% |
| 2012 | WEC | 51.06% | 48.94% | 6.58% |
| 2013 | WEC | 57.77% | 42.23% | 6.50% |
| 1996 | XEL | 71.73% | 28.27% | 6.01% |
| 1997 | XEL | 86.96% | 13.04% | -7.15% |
| 1998 | XEL | 77.72% | 22.28% | 28.57% |
| 1999 | XEL | 101.40% | -1.40% | 33.67% |
| 2000 | XEL | 92.50% | 7.50% | 30.19% |
| 2001 | XEL | 66.08% | 33.92% | 24.32% |
| 2002 | XEL | 269.05% | -169.05% | 40.62% |
| 2003 | XEL | 60.98% | 39.02% | 3.68% |
| 2004 | XEL | 63.78% | 36.22% | 3.44% |
| 2005 | XEL | 70.83% | 29.17% | 5.48% |
| 2006 | XEL | 65.19% | 34.81% | 5.03% |
| 2007 | XEL | 67.41% | 32.59% | 6.54% |
| 2008 | XEL | 64.38% | 35.62% | 5.56% |
| 2009 | XEL | 65.10% | 34.90% | 6.41% |
| 2010 | XEL | 64.10% | 35.90% | 6.16% |
| 2011 | XEL | 59.88% | 40.12% | 5.15% |
| 2012 | XEL | 57.84% | 42.16% | 4.46% |
| 2013 | XEL | 58.12% | 41.88% | 5.29% |

I/A



Retention Ratio Regression Analysis - Mr. O'Donnell's Proxy Group

Source: Value Line

| Company | Ticker | | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1.35 | 2.48 | 2.77 | 3.08 | 2.82 | 1.89 | 2.19 | 2.65 | 2.58 | 2.63 | 2.9 | 3.38 | 3.14 | 3.13 | 3.38 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 0.30 | 1.25 | 1.45 | 1.64 | 1.72 | 1.76 | 1.76 | 1.78 | 1.84 | 1.9 | 1.96 | 2.02 | 2.08 | 2.14 | 2.24 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 22.22% | 50.40% | 52.35% | 53.25% | 60.99% | 93.12% | 80.37% | 67.17% | 71.32% | 72.24% | 67.59% | 59.76% | 66.24% | 68.37% | 66.27% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 83.70% | 11.69% | 11.19% | -8.44% | -32.98% | 15.87% | 21.00% | -2.64% | 1.94% | 10.27% | 16.55% | -7.10% | -0.32% | 7.99% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 13.03% | -0.53% | 1.33% | -1.44% | 0.64% | 9.29% | 9.42% | 3.80% | 4.27% | 5.48% | N/A | N/A | N/A | N/A | N/A |
| Alliant Energy Corporation | LNT | Earnings Per Share | 1.14 | 0.95 | 0.63 | 1.10 | 1.24 | 1.21 | 0.59 | 0.79 | 0.93 | 1.11 | 1.03 | 1.35 | 1.27 | 0.95 | 1.38 | 1.38 | 1.53 | 1.65 | 1.74 | 1.69 | 1.65 | 1.99 | 2.19 |
| | | Dividends Per Share | 0.99 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 0.50 | 0.51 | 0.53 | 0.58 | 0.64 | 0.70 | 0.75 | 0.79 | 0.85 | 0.90 | 0.94 | 1.02 | 1.10 | 1.18 | 1.26 | 1.34 |
| | | Payout Ratio | 86.78% | 105.26% | 158.73% | 91.32% | 80.97% | 82.64% | 169.49% | 63.69% | 55.14% | 47.51% | 55.83% | 47.21% | 55.12% | 78.95% | 57.45% | 61.82% | 59.02% | 56.97% | 58.62% | 65.09% | 71.52% | 63.32% | 61.19% |
| | | Annual Earnings Growth | N/A | -16.30% | -33.68% | 73.81% | 12.79% | -2.02% | -51.24% | 33.05% | 17.83% | 19.46% | -6.79% | 30.58% | -5.58% | -25.20% | 44.74% | 0.00% | 10.91% | 8.20% | 5.45% | -2.87% | -2.37% | 20.61% | 10.05% |
| | | 5yr Avg Fwd EPS Growth | 6.92% | -0.07% | 13.28% | 2.08% | 3.42% | 2.46% | 18.83% | 11.10% | 2.50% | 7.55% | 8.91% | 4.97% | 7.73% | 13.86% | 4.34% | 3.86% | 5.80% | 6.17% | N/A | N/A | N/A | N/A | N/A |
| Ameren Corporation | AEE | Earnings Per Share | 2.86 | 2.44 | 2.82 | 2.81 | 3.33 | 3.41 | 2.66 | 3.14 | 2.82 | 3.13 | 2.66 | 2.98 | 2.88 | 2.78 | 2.77 | 2.47 | 2.41 | 2.10 | 2.40 | 2.38 | 2.68 | 2.77 | 3.32 |
| | | Dividends Per Share | 2.51 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 2.54 | 1.54 | 1.54 | 1.56 | 1.60 | 1.60 | 1.61 | 1.66 | 1.72 | 1.78 | 1.85 |
| | | Payout Ratio | 87.76% | 104.10% | 90.07% | 90.39% | 76.28% | 74.49% | 95.49% | 80.89% | 90.07% | 81.15% | 95.49% | 85.23% | 88.19% | 55.40% | 55.60% | 63.16% | 66.39% | 76.19% | 67.08% | 69.75% | 64.18% | 64.26% | 55.72% |
| | | Annual Earnings Growth | N/A | -14.69% | 15.57% | -0.35% | 18.51% | 2.40% | -21.99% | 18.05% | -10.19% | 10.99% | -15.02% | 12.03% | -3.36% | -3.47% | -0.36% | -10.83% | -2.43% | -12.86% | 14.29% | -0.83% | 12.61% | 3.36% | 19.86% |
| | | 5yr Avg Fwd EPS Growth | 4.29% | 2.83% | 3.32% | 1.35% | -0.15% | -3.63% | 3.17% | -1.11% | 0.24% | -2.03% | -1.20% | -4.09% | -5.99% | -2.44% | -2.53% | 2.15% | 3.31% | 9.85% | N/A | N/A | N/A | N/A | N/A |
| American Electric Power Company, Inc. | AEP | Earnings Per Share | 3.14 | 3.28 | 2.81 | 2.69 | 1.04 | 3.27 | 2.86 | 2.53 | 2.61 | 2.64 | 2.86 | 2.86 | 2.99 | 2.97 | 2.60 | 3.13 | 2.98 | 3.18 | 3.34 | 3.59 | 4.23 | 3.62 | 3.90 |
| | | Dividends Per Share | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 2.40 | 1.65 | 1.40 | 1.42 | 1.50 | 1.58 | 1.64 | 1.64 | 1.71 | 1.85 | 1.88 | 1.95 | 2.03 | 2.15 | 2.27 | 2.39 | 2.53 |
| | | Payout Ratio | 76.43% | 73.17% | 85.41% | 89.22% | 230.77% | 73.39% | 83.92% | 65.22% | 53.64% | 53.79% | 52.45% | 55.24% | 54.85% | 55.22% | 65.77% | 59.11% | 63.09% | 61.32% | 60.78% | 59.89% | 53.66% | 66.02% | 64.87% |
| | | Annual Earnings Growth | N/A | 4.46% | -14.33% | -4.27% | -61.34% | 214.42% | -12.54% | -11.54% | 3.16% | 1.15% | 8.33% | 0.00% | 4.55% | -0.67% | -12.46% | 20.38% | -4.79% | 6.71% | 5.03% | 7.49% | 17.83% | -14.42% | 7.73% |
| | | 5yr Avg Fwd EPS Growth | 27.79% | 24.39% | 24.95% | 26.43% | 38.93% | -2.29% | 0.22% | 3.44% | 2.67% | -0.05% | 2.36% | 1.40% | 1.84% | 2.98% | 6.96% | 6.45% | 4.53% | 4.73% | N/A | N/A | N/A | N/A | N/A |
| CMS Energy Corporation | CMS | Earnings Per Share | 2.45 | 2.61 | 2.24 | 2.85 | 2.53 | 1.27 | -2.99 | -0.29 | 0.74 | 1.1 | 0.64 | 0.64 | 1.23 | 0.93 | 1.33 | 1.45 | 1.53 | 1.66 | 1.74 | 1.89 | 1.98 | 2.17 | 2.32 |
| | | Dividends Per Share | 1.02 | 1.14 | 1.26 | 1.39 | 1.46 | 1.46 | 1.09 | N/A | N/A | N/A | N/A | 0.2 | 0.36 | 0.5 | 0.66 | 0.84 | 0.96 | 1.02 | 1.08 | 1.16 | 1.24 | 1.33 | 1.43 |
| | | Payout Ratio | 41.63% | 43.68% | 56.25% | 48.77% | 57.71% | 114.96% | N/A | N/A | N/A | N/A | N/A | 31.25% | 29.27% | 53.76% | 49.62% | 57.93% | 62.75% | 61.45% | 62.07% | 61.38% | 62.63% | 61.29% | 61.64% |
| | | Annual Earnings Growth | N/A | 6.53% | -14.18% | 27.23% | -11.23% | -49.80% | -335.43% | -90.30% | -355.17% | 48.65% | -41.82% | 0.00% | 92.19% | -24.39% | 43.01% | 9.02% | 5.52% | 8.50% | 4.82% | 8.62% | 4.76% | 9.60% | 6.91% |
| | | 5yr Avg Fwd EPS Growth | -8.29% | -76.68% | -91.91% | -168.39% | -156.41% | -154.82% | -87.73% | -51.23% | 14.93% | 13.80% | 23.97% | 25.07% | 8.33% | 14.17% | 7.30% | 6.44% | 7.26% | 6.94% | N/A | N/A | N/A | N/A | N/A |
| Consolidated Edison, Inc. | ED | Earnings Per Share | N/A | 2.95 | 3.04 | 3.13 | 2.74 | 3.21 | 3.13 | 2.83 | 2.32 | 2.99 | 2.95 | 3.48 | 3.36 | 3.14 | 3.47 | 3.57 | 3.86 | 3.93 | 3.62 | 4.05 | 3.94 | 4.10 | 4.55 |
| | | Dividends Per Share | N/A | 2.10 | 2.12 | 2.14 | 2.18 | 2.20 | 2.22 | 2.24 | 2.26 | 2.28 | 2.30 | 2.32 | 2.34 | 2.36 | 2.38 | 2.40 | 2.42 | 2.46 | 2.52 | 2.60 | 2.68 | 2.76 | 2.86 |
| | | Payout Ratio | N/A | 71.19% | 69.74% | 68.37% | 79.56% | 68.54% | 70.93% | 79.15% | 97.41% | 76.25% | 77.97% | 66.67% | 69.64% | 75.16% | 68.59% | 67.23% | 62.69% | 62.60% | 69.61% | 64.20% | 68.02% | 67.32% | 62.86% |
| | | Return on Common Equity | N/A | N/A | 3.05% | 2.96% | -12.46% | 17.15% | -2.49% | -9.58% | -18.02% | 28.88% | -1.34% | 17.97% | -3.45% | -6.55% | 10.51% | 2.88% | 8.12% | 1.81% | -7.89% | 11.88% | -2.72% | 4.06% | 10.98% |
| | | 5yr Avg Fwd EPS Growth | N/A | 1.64% | -0.88% | -5.08% | 3.19% | -0.51% | 3.58% | 4.81% | 7.10% | 3.43% | 4.27% | 2.30% | 3.36% | 3.09% | 3.36% | 2.24% | 1.43% | 3.26% | N/A | N/A | N/A | N/A | N/A |
| Dominion Energy Inc | D | Earnings Per Share | N/A | 1.50 | 0.86 | 1.50 | 1.25 | 1.49 | 2.41 | 1.96 | 2.13 | 1.50 | 2.40 | 2.13 | 3.04 | 2.64 | 2.89 | 2.76 | 2.75 | 3.09 | 3.05 | 3.20 | 3.44 | 3.53 | 3.25 |
| | | Dividends Per Share | N/A | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.30 | 1.34 | 1.38 | 1.46 | 1.58 | 1.75 | 1.83 | 1.97 | 2.11 | 2.25 | 2.40 | 2.59 | 2.80 | 3.04 | 3.34 |
| | | Payout Ratio | N/A | 86.00% | 150.00% | 86.00% | 103.20% | 86.58% | 53.53% | 65.82% | 61.03% | 89.33% | 57.50% | 68.54% | 51.97% | 66.29% | 63.32% | 71.38% | 76.73% | 72.82% | 78.69% | 80.94% | 81.40% | 86.12% | 102.77% |
| | | Annual Earnings Growth | N/A | N/A | -42.67% | 74.42% | -16.67% | 19.20% | 61.74% | -18.67% | 8.67% | -29.58% | 60.00% | -11.25% | 42.72% | -13.16% | 9.47% | -4.50% | -0.36% | 12.36% | -1.29% | 4.92% | 7.50% | 2.62% | -7.93% |
| | | 5yr Avg Fwd EPS Growth | N/A | 19.21% | 24.00% | 10.86% | 8.27% | 16.43% | 1.83% | 14.11% | 9.75% | 17.56% | 4.66% | 6.83% | 0.76% | 3.14% | 2.23% | 4.62% | 5.22% | 1.16% | N/A | N/A | N/A | N/A | N/A |
| Duke Energy Corporation | DUK | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2.76 | 3.6 | 3.03 | 3.39 | 4.02 | 4.14 | 3.71 | 3.98 | 4.13 | 4.1 | 3.71 | 4.22 | 4.13 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 2.58 | 2.7 | 2.82 | 2.91 | 2.97 | 3.03 | 3.09 | 3.15 | 3.24 | 3.36 | 3.49 | 3.64 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 71.67% | 89.11% | 83.19% | 72.39% | 71.74% | 81.67% | 77.64% | 76.27% | 79.02% | 90.57% | 82.70% | 88.14% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 30.43% | -15.83% | 11.88% | 18.58% | 2.99% | -10.39% | 7.28% | 3.77% | -0.73% | -9.51% | 13.75% | -2.13% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 9.61% | 1.45% | 6.07% | 4.45% | 0.58% | -1.92% | 2.91% | 1.03% | N/A | N/A | N/A | N/A | N/A |
| Edison International | EIX | Earnings Per Share | 1.64 | 1.75 | 1.86 | 2.03 | NA | 1.30 | 1.82 | 2.38 | 0.69 | 3.34 | 3.28 | 3.32 | 3.68 | 3.24 | 3.35 | 3.23 | 4.55 | 3.78 | 4.33 | 4.15 | 3.94 | 4.51 | -1.26 |
| | | Dividends Per Share | 1.00 | 1.00 | 1.04 | 1.08 | 0.83 | N/A | N/A | N/A | 0.80 | 1.02 | 1.10 | 1.18 | 1.23 | 1.25 | 1.27 | 1.29 | 1.31 | 1.37 | 1.48 | 1.73 | 1.98 | 2.23 | 2.43 |
| | | Payout Ratio | 60.98% | 57.14% | 55.91% | 53.20% | N/A | N/A | N/A | N/A | 115.94% | 30.54% | 33.54% | 35.54% | 33.42% | 38.58% | 37.91% | 39.94% | 28.79% | 36.24% | 34.18% | 41.69% | 50.25% | 49.45% | N/A |
| | | Return on Common Equity | N/A | 6.71% | 6.29% | 9.14% | N/A | N/A | 40.00% | 30.77% | -71.01% | 384.06% | -1.80% | 1.22% | 10.84% | -11.96% | 3.40% | -3.58% | 40.87% | -16.92% | 14.55% | -4.16% | -5.06% | 14.47% | -127.94% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | 76.40% | 68.65% | 64.66% | 76.47% | 0.34% | -0.02% | 7.91% | 2.36% | 7.66% | 6.15% | 5.86% | 0.58% | -21.63% | N/A | N/A | N/A | N/A | N/A |
| Entergy Corporation | ETR | Earnings Per Share | N/A | 2.25 | 2.22 | 2.25 | 2.97 | 3.08 | 3.68 | 3.69 | 3.93 | 4.40 | 5.36 | 5.60 | 6.20 | 6.30 | 6.66 | 7.55 | 6.02 | 4.96 | 5.77 | 5.81 | 6.88 | 5.19 | 5.88 |
| | | Dividends Per Share | N/A | 1.80 | 1.50 | 1.20 | 1.22 | 1.28 | 1.34 | 1.60 | 1.89 | 2.16 | 2.16 | 2.58 | 3.00 | 3.00 | 3.24 | 3.32 | 3.32 | 3.32 | 3.32 | 3.34 | 3.42 | 3.50 | 3.58 |
| | | Payout Ratio | N/A | 80.00% | 67.57% | 53.33% | 41.08% | 41.56% | 36.41% | 43.36% | 48.09% | 49.09% | 40.30% | 46.07% | 48.39% | 47.62% | 48.65% | 43.97% | 55.15% | 66.94% | 57.54% | 57.49% | 49.71% | 67.44% | 60.88% |
| | | Return on Common Equity | N/A | N/A | -1.33% | 1.35% | 32.00% | 3.70% | 19.48% | 0.27% | 6.50% | 11.96% | 21.82% | 4.48% | 10.71% | 1.61% | 5.71% | 13.36% | -20.26% | -17.61% | 16.33% | 0.69% | 18.42% | -24.56% | 13.29% |
| | | 5yr Avg Fwd EPS Growth | N/A | 11.04% | 11.36% | 12.39% | 8.38% | 12.01% | 9.01% | 11.09% | 10.12% | 8.87% | 7.18% | 2.23% | -3.44% | -0.49% | -1.50% | -0.49% | -1.35% | 4.83% | N/A | N/A | N/A | N/A | N/A |
| Eversource Energy | ES | Earnings Per Share | N/A | -1.05 | -0.36 | -1.14 | -0.20 | 1.37 | 1.08 | 1.24 | 0.91 | 0.98 | 0.82 | 1.59 | 1.86 | 1.91 | 2.10 | 2.22 | 1.89 | 2.49 | 2.58 | 2.76 | 2.96 | 3.11 | 3.25 |
| | | Dividends Per Share | N/A | 0.25 | N/A | 0.10 | 0.40 | 0.45 | 0.53 | 0.58 | 0.63 | 0.68 | 0.73 | 0.78 | 0.83 | 0.95 | 1.03 | 1.10 | 1.32 | 1.47 | 1.57 | 1.67 | 1.78 | 1.90 | 2.02 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | 32.85% | 49.07% | 46.77% | 69.23% | 69.39% | 89.02% | 49.06% | 44.62% | 49.74% | 49.05% | 49.55% | 69.84% | 59.04% | 60.85% | 60.51% | 60.14% | 61.09% | 62.15% |
| | | Return on Common Equity | N/A | N/A | -65.71% | 216.67% | -82.46% | -785.00% | -21.17% | 14.81% | -26.61% | 7.69% | -16.33% | 93.90% | 16.98% | 2.69% | 9.95% | 5.71% | -14.86% | 31.75% | 3.61% | 6.98% | 7.25% | 5.07% | 4.50% |
| | | 5yr Avg Fwd EPS Growth | N/A | -147.53% | -131.43% | -180.08% | -162.05% | -8.32% | 14.69% | 15.13% | 20.99% | 21.44% | 25.85% | 4.09% | 7.05% | 7.23% | 6.64% | 6.94% | 10.93% | 5.48% | N/A | N/A | N/A | N/A | N/A |
| Hawaiian Electric Industries, Inc. | HE | Earnings Per Share | 1.30 | 1.38 | 1.48 | 1.45 | 1.27 | 1.60 | 1.62 | 1.58 | 1.36 | 1.46 | 1.33 | 1.11 | 1.07 | 0.91 | 1.21 | 1.44 | 1.67 | 1.62 | 1.64 | 1.50 | 2.29 | 1.64 | 1.85 |
| | | Dividends Per Share | 1.21 | 1.22 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| | | Payout Ratio | 93.08% | 88.41% | 83.78% | 85.52% | 97.64% | 77.50% | 76.54% | 78.48% | 91.18% | 84.93% | 93.23% | 111.71% | 115.89% | 136.26% | 102.48% | 86.11% | 74.25% | 76.54% | 75.61% | 82.67% | 54.15% | 75.61% | 67.03% |
| | | Annual Earnings Growth | N/A | 6.15% | 7.25% | -2.03% | -12.41% | 25.98% | 1.25% | -2.47% | -13.92% | 7.35% | -8.90% | -16.54% | -3.60% | -14.95% | 32.97% | 19.01% | 15.97% | -2.99% | 1.23% | -8.54% | 52.67% | -28.38% | 12.80% |
| | | 5yr Avg Fwd EPS Growth | 4.99% | 4.01% | 2.06% | -0.31% | 3.64% | -3.34% | -6.90% | -7.12% | -7.33% | -2.21% | 3.38% | 9.88% | 10.00% | 13.24% | 4.94% | 11.67% | 2.80% | 5.96% | N/A | N/A | N/A | N/A | N/A |
| IDACORP, Inc. | IDA | Earnings Per Share | 2.21 | 2.32 | 2.37 | 2.43 | 3.50 | 3.35 | 1.63 | 0.96 | 1.90 | 1.75 | 2.35 | 1.86 | 2.18 | 2.64 | 2.95 | 3.36 | 3.37 | 3.64 | 3.85 | 3.87 | 3.94 | 4.21 | 4.49 |
| | | Dividends Per Share | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.70 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.20 | 1.37 | 1.57 | 1.76 | 1.92 | 2.08 | 2.24 | 2.40 |
| | | Payout Ratio | 84.16% | 80.17% | 78.48% | 76.54% | 53.14% | 55.52% | 114.11% | 177.08% | 63.16% | 68.57% | 51.06% | 64.52% | 55.05% | 45.45% | 40.68% | 35.71% | 40.65% | 43.13% | 45.71% | 49.61% | 52.79% | 53.21% | 53.45% |
| | | Return on Common Equity | N/A | 4.98% | 2.16% | 2.53% | 44.03% | -4.29% | -51.34% | -41.10% | 97.92% | -7.89% | 34.29% | -20.85% | 17.20% | 21.10% | 11.74% | 13.90% | 0.30% | 8.01% | 5.77% | 0.52% | 1.81% | 6.85% | 6.65% |
| | | 5yr Avg Fwd EPS Growth | 9.88% | -1.38% | -10.03% | 9.04% | -1.34% | 6.37% | 12.47% | 24.13% | 8.77% | 12.70% | 8.62% | 12.85% | 11.01% | 7.94% | 5.70% | 3.28% | 4.59% | 4.32% | N/A | N/A | N/A | N/A | N/A |
| MGE Energy, Inc. | MGEE | Earnings Per Share | N/A | N/A | 0.92 | 0.99 | 1.11 | 1.08 | 1.13 | 1.14 | 1.18 | 1.05 | 1.37 | 1.51 | 1.59 | 1.47 | 1.67 | 1.76 | 1.86 | 2.16 | 2.32 | 2.06 | 2.18 | 2.20 | 2.43 |
| | | Dividends Per Share | N/A | N/A | 0.86 | 0.87 | 0.88 | 0.89 | 0.89 | 0.90 | 0.91 | 0.92 | 0.93 | 0.94 | 0.96 | 0.97 | 0.99 | 1.01 | 1.04 | 1.07 | 1.11 | 1.16 | 1.21 | 1.26 | 1.32 |
| | | Payout Ratio | N/A | N/A | 93.48% | 87.88% | 79.28% | 82.41% | 78.76% | 78.95% | 77.12% | 87.62% | 67.88% | 62.25% | 60.38% | 65.99% | 59.28% | 57.39% | 55.91% | 49.54% | 47.84% | 56.31% | 55.50% | 57.27% | 54.32% |
| | | Return on Common Equity | N/A | N/A | N/A | 7.61% | 12.12% | -2.70% | 4.63% | 0.88% | 3.51% | -11.02% | 30.48% | 10.22% | 5.30% | -7.55% | 13.61% | 5.39% | 5.68% | 16.13% | 7.41% | -11.21% | 5.83% | 0.92% | 10.45% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | 4.51% | 3.69% | -0.94% | 5.70% | 6.81% | 7.70% | 5.49% | 10.41% | 5.39% | 4.49% | 6.65% | 9.64% | 4.68% | 4.77% | 3.81% | 2.68% | N/A | N/A | N/A | N/A | N/A |
| Nextera Energy Inc. | NEE | Earnings Per Share | 1.67 | 1.79 | 1.93 | 2.04 | 2.07 | 2.31 | 2.01 | 2.45 | 2.46 | 2.32 | 3.23 | 3.27 | 4.07 | 3.97 | 4.74 | 4.82 | 4.56 | 4.83 | 5.60 | 6.06 | 5.78 | 6.50 | 6.67 |
| | | Dividends Per Share | 0.92 | 0.96 | 1.00 | 1.04 | 1.08 | 1.12 | 1.16 | 1.20 | 1.30 | 1.42 | 1.50 | 1.64 | 1.78 | 1.89 | 2.00 | 2.20 | 2.40 | 2.64 | 2.90 | 3.08 | 3.48 | 3.93 | 4.44 |
| | | Payout Ratio | 55.26% | 53.63% | 51.81% | 50.98% | 52.17% | 48.48% | 57.71% | 48.98% | 52.85% | 61.21% | 46.44% | 50.15% | 43.73% | 47.61% | 42.19% | 45.64% | 52.63% | 54.66% | 51.79% | 50.83% | 60.21% | 60.46% | 66.57% |
| | | Annual Earnings Growth | N/A | 7.51% | 7.82% | 5.70% | 1.47% | 11.59% | -12.99% | 21.89% | 0.41% | -5.69% | 39.22% | 1.24% | 24.46% | -2.46% | 19.40% | 1.69% | -5.39% | 5.92% | 15.94% | 8.21% | -4.62% | 12.46% | 2.62% |
| | | 5yr Avg Fwd EPS Growth | 6.82% | 2.72% | 5.53% | 4.48% | 3.04% | 8.57% | 11.41% | 11.93% | 11.36% | 16.37% | 8.87% | 7.54% | 3.83% | 7.51% | 5.27% | 4.01% | 7.58% | 6.92% | N/A | N/A | N/A | N/A | N/A |
| NorthWestern Corporation | NWE | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -14.32 | 1.71 | 1.31 | 1.44 | 1.77 | 2.02 | 2.14 | 2.53 | 2.26 | 2.46 | 2.99 | 2.9 | 3.39 | 3.34 | 3.4 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1 | 1.24 | 1.28 | 1.32 | 1.34 | 1.36 | 1.44 | 1.48 | 1.52 | 1.6 | 1.92 | 2 | 2.1 | 2.2 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 58.48% | 94.66% | 88.89% | 74.58% | 66.34% | 63.55% | 56.92% | 65.49% | 61.79% | 53.51% | 66.21% | 59.00% | 62.87% | 64.71% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -111.94% | -23.39% | 9.92% | 22.92% | 14.12% | 5.94% | 18.22% | -10.67% | 8.85% | 21.54% | -3.01% | 16.90% | -1.47% | 1.80% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -17.67% | 5.90% | 14.23% | 10.11% | 7.29% | 8.78% | 6.99% | 6.72% | 8.56% | 7.15% | N/A | N/A | N/A | N/A | N/A |
| OGE Energy Corp. | OGE | Earnings Per Share | N/A | N/A | 1.02 | 0.97 | 0.95 | 0.65 | 0.72 | 0.87 | 0.89 | 0.92 | 1.23 | 1.32 | 1.25 | 1.33 | 1.50 | 1.73 | 1.79 | 1.94 | 1.98 | 1.69 | 1.69 | 1.92 | 2.12 |
| | | Dividends Per Share | N/A | N/A | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.67 | 0.68 | 0.70 | 0.71 | 0.73 | 0.76 | 0.80 | 0.85 | 0.95 | 1.05 | 1.16 | 1.27 | 1.40 |
| | | Payout Ratio | N/A | N/A | 65.69% | 69.07% | 70.53% | 103.08% | 93.06% | 77.01% | 75.28% | 72.83% | 54.47% | 51.52% | 56.00% | 53.38% | 48.67% | 43.93% | 44.69% | 43.81% | 47.98% | 62.13% | 68.64% | 66.15% | 66.04% |
| | | Annual Earnings Growth | N/A | N/A | N/A | -4.90% | -2.06% | -31.58% | 10.77% | 20.83% | 2.30% | 3.37% | 33.70% | 7.32% | -5.30% | 6.40% | 12.78% | 15.33% | 3.47% | 8.38% | 2.06% | -14.65% | 0.00% | 13.61% | 10.42% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | -1.39% | 0.05% | 1.14% | 14.19% | 13.50% | 8.28% | 9.10% | 10.98% | 7.31% | 6.54% | 9.27% | 8.41% | 2.92% | -0.15% | 1.88% | 2.29% | N/A | N/A | N/A | N/A | N/A |
| Otter Tail Corporation | OTTR | Earnings Per Share | 1.24 | 1.29 | 1.29 | 1.45 | 1.60 | 1.68 | 1.79 | 1.51 | 1.50 | 1.78 | 1.69 | 1.78 | 1.09 | 0.71 | 0.38 | 0.45 | 1.05 | 1.37 | 1.55 | 1.56 | 1.60 | 1.86 | 2.06 |
| | | Dividends Per Share | 0.90 | 0.93 | 0.96 | 0.99 | 1.02 | 1.04 | 1.06 | 1.08 | 1.10 | 1.12 | 1.15 | 1.17 | 1.19 | 1.19 | 1.19 | 1.19 | 1.19 | 1.19 | 1.21 | 1.23 | 1.25 | 1.28 | 1.34 |
| | | Payout Ratio | 72.58% | 72.09% | 74.42% | 68.28% | 63.75% | 61.90% | 59.22% | 71.52% | 73.33% | 62.92% | 68.05% | 65.73% | 109.17% | 167.61% | 313.16% | 264.44% | 113.33% | 86.86% | 78.06% | 78.85% | 78.13% | 68.82% | 65.05% |
| | | Annual Earnings Growth | N/A | 4.03% | 0.00% | 12.40% | 10.34% | 5.00% | 6.55% | -15.64% | -0.66% | 18.67% | -5.06% | 5.33% | -38.76% | -34.86% | -46.48% | 18.42% | 133.33% | 30.48% | 13.14% | 0.65% | 2.56% | 16.25% | 10.75% |
| | | 5yr Avg Fwd EPS Growth | 6.36% | 6.86% | 3.73% | 1.12% | 2.78% | 0.77% | 0.53% | -4.10% | -10.94% | -23.97% | -19.27% | 6.33% | 20.18% | 29.78% | 39.20% | 36.03% | 12.61% | 8.67% | N/A | N/A | N/A | N/A | N/A |
| Pinnacle West Capital Corporation | PNW | Earnings Per Share | 2.47 | 2.76 | 2.85 | 3.18 | 3.35 | 3.68 | 2.53 | 2.52 | 2.58 | 2.24 | 3.17 | 2.96 | 2.12 | 2.26 | 3.08 | 2.99 | 3.50 | 3.66 | 3.58 | 3.92 | 3.95 | 4.43 | 4.54 |
| | | Dividends Per Share | 1.03 | 1.13 | 1.23 | 1.33 | 1.43 | 1.53 | 1.63 | 1.73 | 1.83 | 1.93 | 2.03 | 2.10 | 2.10 | 2.10 | 2.10 | 2.10 | 2.67 | 2.23 | 2.33 | 2.44 | 2.56 | 2.70 | 2.87 |
| | | Payout Ratio | 41.70% | 40.94% | 43.16% | 41.82% | 42.69% | 41.58% | 64.43% | 68.65% | 70.93% | 86.16% | 64.04% | 70.95% | 99.06% | 92.92% | 68.18% | 70.23% | 76.29% | 60.93% | 65.08% | 62.24% | 64.81% | 60.95% | 63.22% |
| | | Annual Earnings Growth | N/A | 11.74% | 3.26% | 11.58% | 5.35% | 9.85% | -31.25% | -0.40% | 2.38% | -13.18% | 41.52% | -6.62% | -28.38% | 6.60% | 36.28% | -2.92% | 17.06% | 4.57% | -2.19% | 9.50% | 0.77% | 12.15% | 2.48% |
| | | 5yr Avg Fwd EPS Growth | 8.36% | -0.24% | -0.97% | -2.81% | -6.52% | -0.18% | 4.74% | -0.86% | -0.01% | 9.88% | 0.99% | 5.73% | 12.32% | 10.56% | 5.20% | 5.94% | 4.96% | 4.54% | N/A | N/A | N/A | N/A | N/A |
| PNM Resources, Inc. | PNM | Earnings Per Share | 1.15 | 1.25 | 1.50 | 1.29 | 1.55 | 2.61 | 1.07 | 1.15 | 1.43 | 1.56 | 1.72 | 0.76 | 0.11 | 0.58 | 0.87 | 1.08 | 1.31 | 1.41 | 1.45 | 1.64 | 1.65 | 1.92 | 1.66 |
| | | Dividends Per Share | 0.24 | 0.42 | 0.51 | 0.53 | 0.53 | 0.53 | 0.57 | 0.61 | 0.63 | 0.79 | 0.86 | 0.91 | 0.61 | 0.50 | 0.50 | 0.50 | 0.58 | 0.68 | 0.76 | 0.80 | 0.88 | 0.99 | 1.09 |
| | | Payout Ratio | 20.87% | 33.60% | 34.00% | 41.09% | 34.19% | 20.31% | 53.27% | 53.04% | 44.06% | 50.64% | 50.00% | 119.74% | 554.55% | 86.21% | 57.47% | 46.30% | 44.27% | 48.23% | 52.41% | 48.78% | 53.33% | 51.56% | 65.66% |
| | | Annual Earnings Growth | N/A | 8.70% | 20.00% | -14.00% | 20.16% | 68.39% | -59.00% | 7.48% | 24.35% | 9.09% | 10.26% | -55.81% | -85.53% | 427.27% | 50.00% | 24.14% | 21.30% | 7.63% | 2.84% | 13.10% | 0.61% | 16.36% | -13.54% |
| | | 5yr Avg Fwd EPS Growth | 20.65% | 7.11% | 4.60% | 12.27% | 10.06% | -1.57% | -0.93% | -19.53% | 61.06% | 69.24% | 72.01% | 87.44% | 106.07% | 21.18% | 13.80% | 9.10% | 8.11% | 3.87% | N/A | N/A | N/A | N/A | N/A |
| Portland General Electric Company | POR | Earnings Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 1.02 | 1.14 | 2.33 | 1.39 | 1.31 | 1.66 | 1.95 | 1.87 | 1.77 | 2.18 | 2.04 | 2.16 | 2.29 | 2.37 |
| | | Dividends Per Share | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 0.68 | 0.93 | 0.97 | 1.01 | 1.04 | 1.06 | 1.08 | 1.10 | 1.12 | 1.18 | 1.26 | 1.34 | 1.43 |
| | | Payout Ratio | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 59.65% | 39.91% | 69.78% | 77.10% | 62.65% | 54.36% | 57.75% | 62.15% | 51.38% | 57.84% | 58.33% | 58.52% | 60.34% |
| | | Annual Earnings Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 11.76% | 104.39% | -40.34% | -5.76% | 26.72% | 17.47% | -4.10% | -5.35% | 23.16% | -6.42% | 5.88% | 6.02% | 3.49% |
| | | 5yr Avg Fwd EPS Growth | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | 19.35% | 20.49% | -1.20% | 5.80% | 11.58% | 4.95% | 2.63% | 4.66% | 6.43% | N/A | N/A | N/A | N/A | N/A |
| Public Service Enterprise Group Incorporated | PEG | Earnings Per Share | N/A | 1.21 | 1.40 | 1.56 | 1.78 | 1.85 | 1.88 | 1.88 | 1.52 | 1.79 | 1.85 | 2.59 | 2.90 | 3.08 | 3.07 | 3.11 | 2.44 | 2.45 | 2.99 | 3.30 | 2.83 | 2.82 | 2.76 |
| | | Dividends Per Share | N/A | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.10 | 1.12 | 1.14 | 1.17 | 1.29 | 1.33 | 1.37 | 1.37 | 1.42 | 1.44 | 1.48 | 1.56 | 1.64 | 1.72 | 1.80 |
| | | Payout Ratio | N/A | 89.26% | 77.14% | 69.23% | 60.67% | 58.38% | 57.45% | 57.45% | 72.37% | 62.57% | 61.62% | 45.17% | 44.48% | 43.18% | 44.63% | 44.05% | 58.20% | 58.78% | 49.50% | 47.27% | 57.95% | 60.99% | 65.22% |
| | | Return on Common Equity | N/A | N/A | 15.70% | 11.43% | 14.10% | 3.93% | 1.62% | 0.00% | -19.15% | 17.76% | 3.35% | 40.00% | 11.97% | 6.21% | -0.32% | 1.30% | -21.54% | 0.41% | 22.04% | 10.37% | -14.24% | -0.35% | -2.13% |
| | | 5yr Avg Fwd EPS Growth | N/A | 9.36% | 6.22% | 0.10% | 0.83% | 0.72% | 8.39% | 10.79% | 15.86% | 12.24% | 11.83% | -0.48% | -2.79% | 0.38% | 2.52% | -0.59% | 3.64% | 3.14% | N/A | N/A | N/A | N/A | N/A |
| Sempra Energy | SRE | Earnings Per Share | 1.98 | 2.20 | 1.24 | 1.66 | 2.06 | 2.55 | 2.79 | 3.01 | 3.93 | 3.52 | 4.23 | 4.26 | 4.43 | 4.78 | 4.02 | 4.47 | 4.35 | 4.22 | 4.63 | 5.23 | 4.24 | 4.63 | 5.48 |
| | | Dividends Per Share | 1.56 | 1.56 | 1.56 | 1.56 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.16 | 1.20 | 1.24 | 1.37 | 1.56 | 1.56 | 1.92 | 2.40 | 2.52 | 2.64 | 2.80 | 3.02 | 3.29 | 3.58 |
| | | Payout Ratio | 78.79% | 70.91% | 125.81% | 93.98% | 48.54% | 39.22% | 35.84% | 33.22% | 25.45% | 32.95% | 28.37% | 29.11% | 30.93% | 32.64% | 38.81% | 42.95% | 55.17% | 59.72% | 57.02% | 53.54% | 71.23% | 71.06% | 65.33% |
| | | Return on Common Equity | N/A | 11.11% | -43.64% | 33.87% | 24.10% | 23.79% | 9.41% | 7.89% | 30.56% | -10.43% | 20.17% | 0.71% | 3.99% | 7.90% | -15.90% | 11.19% | -2.68% | -2.99% | 9.72% | 12.96% | -18.93% | 9.20% | 18.36% |
| | | 5yr Avg Fwd EPS Growth | 9.85% | 9.51% | 19.81% | 19.15% | 12.24% | 11.52% | 9.78% | 9.00% | 4.47% | 3.37% | 1.58% | 0.90% | -0.50% | -0.13% | 5.64% | -0.39% | 1.99% | 6.26% | N/A | N/A | N/A | N/A | N/A |
| Southern Company | SO | Earnings Per Share | 1.68 | 1.58 | 1.73 | 1.83 | 2.01 | 1.61 | 1.85 | 1.97 | 2.06 | 2.13 | 2.10 | 2.28 | 2.25 | 2.32 | 2.36 | 2.55 | 2.67 | 2.70 | 2.77 | 2.84 | 2.83 | 3.21 | 3.00 |
| | | Dividends Per Share | 1.26 | 1.30 | 1.34 | 1.34 | 1.34 | 1.34 | 1.36 | 1.39 | 1.42 | 1.48 | 1.54 | 1.60 | 1.66 | 1.73 | 1.80 | 1.87 | 1.94 | 2.01 | 2.08 | 2.15 | 2.22 | 2.30 | 2.38 |
| | | Payout Ratio | 75.00% | 82.28% | 77.46% | 73.22% | 66.67% | 83.23% | 73.51% | 70.56% | 68.93% | 69.48% | 73.33% | 70.18% | 73.78% | 74.57% | 76.27% | 73.33% | 72.66% | 74.44% | 75.09% | 75.70% | 78.45% | 71.65% | 79.33% |
| | | Annual Earnings Growth | N/A | -5.95% | 9.49% | 5.78% | 9.84% | -19.90% | 14.91% | 6.49% | 4.57% | 3.40% | -1.41% | 8.57% | -1.32% | 3.11% | 1.72% | 8.05% | 4.71% | 1.12% | 2.59% | 2.53% | -0.35% | 13.43% | -6.54% |
| | | 5yr Avg Fwd EPS Growth | -0.15% | 4.02% | 3.42% | 3.18% | 1.89% | 5.59% | 4.32% | 2.76% | 2.47% | 2.14% | 4.03% | 3.26% | 3.74% | 3.64% | 3.80% | 2.12% | 3.86% | 2.33% | N/A | N/A | N/A | N/A | N/A |
| WEC Energy Group | WEC | Earnings Per Share | 0.99 | 0.27 | 0.83 | 0.94 | 0.54 | 0.92 | 1.16 | 1.13 | 0.93 | 1.28 | 1.32 | 1.42 | 1.52 | 1.6 | 1.92 | 2.18 | 2.35 | 2.51 | 2.59 | 2.34 | 2.96 | 3.14 | 3.34 |
| | | Dividends Per Share | 0.75 | 0.77 | 0.78 | 0.78 | 0.69 | 0.40 | 0.40 | 0.40 | 0.42 | 0.44 | 0.46 | 0.50 | 0.54 | 0.68 | 0.80 | 1.04 | 1.20 | 1.45 | 1.56 | 1.74 | 1.98 | 2.08 | 2.21 |
| | | Payout Ratio | 75.76% | 285.19% | 93.98% | 82.98% | 127.78% | 43.48% | 34.48% | 35.40% | 45.16% | 34.38% | 34.85% | 35.21% | 35.53% | 42.50% | 41.67% | 47.71% | 51.06% | 57.77% | 60.23% | 74.36% | 66.89% | 66.24% | 66.17% |
| | | Annual Earnings Growth | N/A | -72.73% | 207.41% | 13.25% | -42.55% | 70.37% | 26.09% | -2.59% | -17.70% | 37.63% | 3.13% | 7.58% | 7.04% | 5.26% | 20.00% | 13.54% | 7.80% | 6.81% | 3.19% | -9.65% | 26.50% | 6.08% | 6.37% |
| | | 5yr Avg Fwd EPS Growth | 35.15% | 54.91% | 12.91% | 6.72% | 22.76% | 9.31% | 5.61% | 7.54% | 12.13% | 8.60% | 10.68% | 10.73% | 10.68% | 10.27% | 4.34% | 6.93% | 6.58% | 6.50% | N/A | N/A | N/A | N/A | N/A |
| Xcel Energy Inc. | XEL | Earnings Per Share | 1.91 | 1.61 | 1.84 | 1.43 | 1.60 | 2.27 | 0.42 | 1.23 | 1.27 | 1.20 | 1.35 | 1.35 | 1.46 | 1.49 | 1.56 | 1.72 | 1.85 | 1.91 | 2.03 | 2.10 | 2.21 | 2.30 | 2.47 |
| | | Dividends Per Share | 1.37 | 1.40 | 1.43 | 1.45 | 1.48 | 1.50 | 1.13 | 0.75 | 0.81 | 0.85 | 0.88 | 0.91 | 0.94 | 0.97 | 1.00 | 1.03 | 1.07 | 1.11 | 1.20 | 1.28 | 1.36 | 1.44 | 1.52 |
| | | Payout Ratio | 71.73% | 86.96% | 77.72% | 101.40% | 92.50% | 66.08% | 269.05% | 60.98% | 63.78% | 70.83% | 65.19% | 67.41% | 64.38% | 65.10% | 64.10% | 59.88% | 57.84% | 58.12% | 59.11% | 60.95% | 61.54% | 62.61% | 61.54% |
| | | Annual Earnings Growth | N/A | -15.71% | 14.29% | -22.28% | 11.89% | 41.88% | -81.50% | 192.86% | 3.25% | -5.51% | 12.50% | 0.00% | 8.15% | 2.05% | 4.70% | 10.26% | 7.56% | 3.24% | 6.28% | 3.45% | 5.24% | 4.07% | 7.39% |
| | | 5yr Avg Fwd EPS Growth | 6.01% | -7.15% | 28.57% | 33.67% | 30.19% | 24.32% | 40.62% | 3.68% | 3.44% | 5.48% | 5.03% | 6.54% | 5.56% | 6.41% | 6.16% | 5.15% | 4.46% | 5.29% | N/A | N/A | N/A | N/A | N/A |

Retention Growth Estimate Vs. Value Line EPS Growth Estimate

| Company | Ticker | [1] Actual/ Projected Earnings per share 2019 | [2] Actual/ Projected Dividend per share 2019 | [3] Retention Ratio (B) | [4] Projected Book Value per Share 2019 | [5] Return on Book Value (R) | [6] B x R | [7] Projected Common Shares Outstanding 2019 | [8] Projected Common Shares Outstanding (3-5 Year) | [9] Common Shares Growth Rate | [10] 2019 High Price | [11] 2019 Low Price | [12] 2019 price midpoint | [13] Market/ Book Ratio | [14] "S" | [15] "V" | [16] S x V | [17] BR + SV | 2019 Value Line Projected EPS Growth | Sustainable Growth Minus EPS Growth | Actual 2018 EPS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 3.33 | 2.35 | 29.43% | 43.17 | 7.71% | 2.27% | 51.70 | 53.00 | 0.62% | $ 88.60 | $ 72.50 | $ 80.55 | 1.87 | 1.16% | 46.41% | 0.54% | 2.81% | -1.48% | 4.29% | 3.38 |
| Alliant Energy Corporation | LNT | 2.33 | 1.42 | 39.06% | 21.24 | 10.97% | 4.28% | 245.02 | 260.00 | 1.49% | $ 54.60 | $ 40.80 | $ 47.70 | 2.25 | 3.36% | 55.47% | 1.86% | 6.15% | 6.39% | -0.25% | 2.19 |
| American Electric Power Company, Inc. | AEP | 4.08 | 2.71 | 33.58% | 39.73 | 10.27% | 3.45% | 494.17 | 530.00 | 1.77% | $ 96.20 | $ 72.30 | $ 84.25 | 2.12 | 3.74% | 52.84% | 1.98% | 5.43% | 4.62% | 0.81% | 3.90 |
| Ameren Corporation | AEE | 3.35 | 1.92 | 42.69% | 32.73 | 10.24% | 4.37% | 246.20 | 275.00 | 2.80% | $ 80.90 | $ 63.10 | $ 72.00 | 2.20 | 6.17% | 54.54% | 3.36% | 7.73% | 0.90% | 6.83% | 3.32 |
| CMS Energy Corporation | CMS | 2.39 | 1.53 | 35.98% | 17.68 | 13.52% | 4.86% | 283.86 | 300.00 | 1.39% | $ 65.30 | $ 48.00 | $ 56.65 | 3.20 | 4.46% | 68.79% | 3.07% | 7.93% | 3.02% | 4.92% | 2.32 |
| Consolidated Edison, Inc. | ED | 3.95 | 2.96 | 25.06% | 53.65 | 7.36% | 1.85% | 334.00 | 345.00 | 0.81% | $ 95.00 | $ 73.30 | $ 84.15 | 1.57 | 1.28% | 36.24% | 0.46% | 2.31% | -13.19% | 15.49% | 4.55 |
| Dominion Energy Inc | D | 2.15 | 3.67 | -70.70% | 34.55 | 6.22% | -4.40% | 824.00 | 865.00 | 1.22% | $ 83.90 | $ 67.40 | $ 75.65 | 2.19 | 2.67% | 54.33% | 1.45% | -2.95% | -33.85% | 30.90% | 3.25 |
| Duke Energy Corporation | DUK | 5.05 | 3.75 | 25.74% | 61.75 | 8.18% | 2.11% | 733.00 | 775.00 | 1.40% | $ 97.40 | $ 82.50 | $ 89.95 | 1.46 | 2.04% | 31.35% | 0.64% | 2.75% | 22.28% | -19.53% | 4.13 |
| Edison International | EIX | 4.65 | 2.48 | 46.67% | 37.90 | 12.27% | 5.73% | 365.00 | 385.00 | 1.34% | $ 76.40 | $ 53.40 | $ 64.90 | 1.71 | 2.30% | 41.60% | 0.96% | 6.68% | NA | NA | -1.26 |
| Entergy Corp. | ETR | 6.30 | 3.66 | 41.90% | 51.34 | 12.27% | 5.14% | 199.15 | 212.00 | 1.58% | $ 122.10 | $ 83.20 | $ 102.65 | 2.00 | 3.15% | 49.99% | 1.57% | 6.72% | 7.14% | -0.43% | 5.88 |
| Eversource Energy | ES | 3.45 | 2.14 | 37.97% | 37.70 | 9.15% | 3.47% | 324.00 | 355.00 | 2.31% | $ 86.60 | $ 63.10 | $ 74.85 | 1.99 | 4.59% | 49.63% | 2.28% | 5.75% | 6.15% | -0.40% | 3.25 |
| Hawaiian Electric Industries, Inc. | HE | 1.90 | 1.28 | 32.63% | 20.45 | 9.29% | 3.03% | 109.00 | 113.00 | 0.91% | $ 47.60 | $ 35.10 | $ 41.35 | 2.02 | 1.83% | 50.54% | 0.92% | 3.96% | 2.70% | 1.25% | 1.85 |
| IDACORP Inc. | IDA | 4.45 | 2.56 | 42.47% | 48.85 | 9.11% | 3.87% | 50.40 | 50.40 | 0.00% | $ 114.00 | $ 89.30 | $ 101.65 | 2.08 | 0.00% | 51.94% | 0.00% | 3.87% | -0.89% | 4.76% | 4.49 |
| MGE Energy Inc | MGEE | 2.51 | 1.38 | 45.02% | 24.68 | 10.17% | 4.58% | 34.67 | 34.67 | 0.00% | $ 80.80 | $ 56.70 | $ 68.75 | 2.79 | 0.00% | 64.10% | 0.00% | 4.58% | 3.29% | 1.29% | 2.43 |
| NextEra Energy, Inc. | NEE | 7.76 | 5.00 | 35.57% | 75.65 | 10.26% | 3.65% | 489.00 | 495.00 | 0.31% | $ 245.00 | $ 168.70 | $ 206.85 | 2.73 | 0.83% | 63.43% | 0.53% | 4.18% | 16.34% | -12.16% | 6.67 |
| NorthWestern Corporation | NWE | 3.55 | 2.30 | 35.21% | 40.20 | 8.83% | 3.11% | 50.50 | 51.60 | 0.54% | $ 76.70 | $ 57.30 | $ 67.00 | 1.67 | 0.90% | 40.00% | 0.36% | 3.47% | 4.41% | -0.94% | 3.40 |
| OGE Energy Corp. | OGE | 2.24 | 1.51 | 32.59% | 20.69 | 10.83% | 3.53% | 200.10 | 200.00 | -0.01% | $ 45.80 | $ 38.00 | $ 41.90 | 2.03 | -0.03% | 50.62% | -0.01% | 3.52% | 5.66% | -2.14% | 2.12 |
| Otter Tail Corporation | OTTR | 2.17 | 1.40 | 35.48% | 19.46 | 11.15% | 3.96% | 40.16 | 41.50 | 0.82% | $ 57.70 | $ 45.90 | $ 51.80 | 2.66 | 2.19% | 62.43% | 1.37% | 5.33% | 5.34% | -0.01% | 2.06 |
| Pinnacle West Capital Corporation | PNW | 4.50 | 3.04 | 32.44% | 47.70 | 9.43% | 3.06% | 113.00 | 118.00 | 1.09% | $ 99.80 | $ 81.60 | $ 90.70 | 1.90 | 2.07% | 47.41% | 0.98% | 4.04% | -0.88% | 4.92% | 4.54 |
| PNM Resources, Inc. | PNM | 2.20 | 1.18 | 46.36% | 20.80 | 10.58% | 4.90% | 79.65 | 90.00 | 3.10% | $ 53.00 | $ 39.70 | $ 46.35 | 2.23 | 6.91% | 55.12% | 3.81% | 8.71% | 32.53% | -23.82% | 1.66 |
| Portland General Electric Company | POR | 2.40 | 1.52 | 36.67% | 28.90 | 8.30% | 3.04% | 89.40 | 90.00 | 0.17% | $ 58.40 | $ 44.00 | $ 51.20 | 1.77 | 0.30% | 43.55% | 0.13% | 3.17% | 1.27% | 1.91% | 2.37 |
| Public Service Enterprie Group, Inc. | PEG | 3.70 | 1.88 | 49.19% | 29.65 | 12.48% | 6.14% | 506.00 | 506.00 | 0.00% | $ 63.90 | $ 50.00 | $ 56.95 | 1.92 | 0.00% | 47.94% | 0.00% | 6.14% | 34.06% | -27.92% | 2.76 |
| SEMPRA Energy | SRE | 5.85 | 3.87 | 33.85% | 61.25 | 9.55% | 3.23% | 290.00 | 320.00 | 2.49% | $ 154.50 | $ 106.10 | $ 130.30 | 2.13 | 5.30% | 52.99% | 2.81% | 6.04% | 6.75% | -0.71% | 5.48 |
| Southern Company | SO | 3.10 | 2.46 | 20.65% | 26.20 | 11.83% | 2.44% | 1050.00 | 1080.00 | 0.71% | $ 64.30 | $ 43.30 | $ 53.80 | 2.05 | 1.45% | 51.30% | 0.74% | 3.19% | 3.33% | -0.15% | 3.00 |
| WEC Energy Group, Inc. | WEC | 3.58 | 2.36 | 34.08% | 32.06 | 11.17% | 3.81% | 315.50 | 315.50 | 0.00% | $ 98.20 | $ 67.20 | $ 82.70 | 2.58 | 0.00% | 61.23% | 0.00% | 3.81% | 7.19% | -3.38% | 3.34 |
| Xcel Energy Inc. | XEL | 2.60 | 1.62 | 37.69% | 25.15 | 10.34% | 3.90% | 525.00 | 546.00 | 0.99% | $ 66.10 | $ 47.70 | $ 56.90 | 2.26 | 2.23% | 55.80% | 1.24% | 5.14% | 5.26% | -0.12% | 2.47 |
| | | | Average: | 32.20% | | | | | | | | | | | | | Mean: | 4.63% | 5.13% | -0.58% | |
| | | | | | | | | | | | | | | | | | Median: | 4.38% | 4.62% | -0.12% | |
| | | | | | | | | | | | | | | | | | | | Number of underestimates: | 14 | |
| | | | | | | | | | | | | | | | | | | | Number of overestimates: | 11 | |

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.33 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Equals [12] / [13]
[14] Equals [9] x [14]
[15] Equals 1 - (1 / [14])
[16] Equals [15] x [16]
[17] Equals [6] + [17]

Retention Growth Estimate Vs. Value Line EPS Growth Estimate

| Company | Ticker | [1] Projected Earnings per share (3-5 Year) | [2] Projected Dividend per share (3-5 Year) | [3] Retention Ratio (B) | [4] Projected Book Value per Share (3-5 Year) | [5] Return on Book Value (R) | [6] B x R | [7] Projected Common Shares Outstanding 2019 | [8] Projected Common Shares Outstanding (3-5 Year) | [9] Common Shares Growth Rate | [10] 2019 High Price | [11] 2019 Low Price | [12] 2019 price midpoint | [13] Projected Book Value per Share 2019 | [14] Market/ Book Ratio | [15] "S" | [16] "V" | [17] S x V | [18] 2022/2023 BR + SV | [19] 2019 BR + SV | [20] Average 2019/2022-23 BR + SV | 2023-2025/ 2022-24 Value Line Projected Annual EPS Growth | Average 2019/ 2022-23 Sustainable Growth Minus EPS Growth |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALLETE, Inc. | ALE | 4.25 | 2.85 | 32.94% | 52.50 | 8.10% | 2.67% | 51.70 | 53.00 | 0.62% | $ 88.60 | $ 72.50 | $ 80.55 | 43.17 | 1.87 | 1.16% | 46.41% | 0.54% | 3.21% | 2.81% | 3.01% | 6.29% | -3.28% |
| Alliant Energy Corporation | LNT | 2.80 | 1.74 | 37.86% | 28.80 | 9.72% | 3.68% | 245.02 | 260.00 | 1.49% | $ 54.60 | $ 40.80 | $ 47.70 | 21.24 | 2.25 | 3.36% | 55.47% | 1.86% | 5.54% | 6.15% | 5.84% | 4.70% | 1.14% |
| American Electric Power Company, Inc. | AEP | 5.00 | 3.35 | 33.00% | 50.00 | 10.00% | 3.30% | 494.17 | 530.00 | 1.77% | $ 96.20 | $ 72.30 | $ 84.25 | 39.73 | 2.12 | 3.74% | 52.84% | 1.98% | 5.28% | 5.43% | 5.35% | 5.21% | 0.14% |
| Ameren Corporation | AEE | 4.25 | 2.35 | 44.71% | 44.00 | 9.66% | 4.32% | 246.20 | 275.00 | 2.80% | $ 80.90 | $ 63.10 | $ 72.00 | 32.73 | 2.20 | 6.17% | 54.54% | 3.36% | 7.68% | 7.73% | 7.71% | 6.13% | 1.58% |
| CMS Energy Corporation | CMS | 3.25 | 2.00 | 38.46% | 25.50 | 12.75% | 4.90% | 283.86 | 300.00 | 1.39% | $ 65.30 | $ 48.00 | $ 56.65 | 17.68 | 3.20 | 4.46% | 68.79% | 3.07% | 7.97% | 7.93% | 7.95% | 7.99% | -0.04% |
| Consolidated Edison, Inc. | ED | 5.25 | 3.50 | 33.33% | 62.50 | 8.40% | 2.80% | 334.00 | 345.00 | 0.81% | $ 95.00 | $ 73.30 | $ 84.15 | 53.65 | 1.57 | 1.28% | 36.24% | 0.46% | 3.26% | 2.31% | 2.79% | 7.37% | -4.59% |
| Dominion Energy Inc | D | 5.50 | 4.15 | 24.55% | 41.00 | 13.41% | 3.29% | 824.00 | 865.00 | 1.22% | $ 83.90 | $ 67.40 | $ 75.65 | 34.55 | 2.19 | 2.67% | 54.33% | 1.45% | 4.75% | -2.95% | 0.90% | 26.47% | -25.57% |
| Duke Energy Corporation | DUK | 6.00 | 4.10 | 31.67% | 71.75 | 8.36% | 2.65% | 733.00 | 775.00 | 1.40% | $ 97.40 | $ 82.50 | $ 89.95 | 61.75 | 1.46 | 2.04% | 31.35% | 0.64% | 3.29% | 2.75% | 3.02% | 4.40% | -1.39% |
| Edison International | EIX | 5.25 | 2.90 | 44.76% | 47.75 | 10.99% | 4.92% | 365.00 | 385.00 | 1.34% | $ 76.40 | $ 53.40 | $ 64.90 | 37.90 | 1.71 | 2.30% | 41.60% | 0.96% | 5.88% | 6.68% | 6.28% | 3.08% | 3.20% |
| Entergy Corp. | ETR | 6.75 | 4.30 | 36.30% | 63.00 | 10.71% | 3.89% | 199.15 | 212.00 | 1.58% | $ 122.10 | $ 83.20 | $ 102.65 | 51.34 | 2.00 | 3.15% | 49.99% | 1.57% | 5.46% | 6.72% | 6.09% | 1.74% | 4.35% |
| Eversource Energy | ES | 4.50 | 2.85 | 36.67% | 48.50 | 9.28% | 3.40% | 324.00 | 355.00 | 2.31% | $ 86.60 | $ 63.10 | $ 74.85 | 37.70 | 1.99 | 4.59% | 49.63% | 2.28% | 5.68% | 5.75% | 5.72% | 6.87% | -1.15% |
| Hawaiian Electric Industries, Inc. | HE | 2.25 | 1.50 | 33.33% | 24.00 | 9.38% | 3.13% | 109.00 | 113.00 | 0.91% | $ 47.60 | $ 35.10 | $ 41.35 | 20.45 | 2.02 | 1.83% | 50.54% | 0.92% | 4.05% | 3.96% | 4.00% | 4.32% | -0.31% |
| IDACORP Inc. | IDA | 5.25 | 3.35 | 36.19% | 56.25 | 9.33% | 3.38% | 50.40 | 50.40 | 0.00% | $ 114.00 | $ 89.30 | $ 101.65 | 48.85 | 2.08 | 0.00% | 51.94% | 0.00% | 3.38% | 3.87% | 3.62% | 4.22% | -0.60% |
| MGE Energy Inc | MGEE | 3.25 | 1.70 | 47.69% | 31.25 | 10.40% | 4.96% | 34.67 | 34.67 | 0.00% | $ 80.80 | $ 56.70 | $ 68.75 | 24.68 | 2.79 | 0.00% | 64.10% | 0.00% | 4.96% | 4.58% | 4.77% | 6.67% | -1.90% |
| NextEra Energy, Inc. | NEE | 12.50 | 8.00 | 36.00% | 97.50 | 12.82% | 4.62% | 489.00 | 495.00 | 0.31% | $ 245.00 | $ 168.70 | $ 206.85 | 75.65 | 2.73 | 0.83% | 63.43% | 0.53% | 5.14% | 4.18% | 4.66% | 12.66% | -8.00% |
| NorthWestern Corporation | NWE | 3.75 | 2.70 | 28.00% | 44.50 | 8.43% | 2.36% | 50.50 | 51.60 | 0.54% | $ 76.70 | $ 57.30 | $ 67.00 | 40.20 | 1.67 | 0.90% | 40.00% | 0.36% | 2.72% | 3.47% | 3.09% | 1.38% | 1.71% |
| OGE Energy Corp. | OGE | 2.75 | 1.85 | 32.73% | 24.25 | 11.34% | 3.71% | 200.10 | 200.00 | -0.01% | $ 45.80 | $ 38.00 | $ 41.90 | 20.69 | 2.03 | -0.03% | 50.62% | -0.01% | 3.70% | 3.52% | 3.61% | 5.26% | -1.65% |
| Otter Tail Corporation | OTTR | 2.50 | 1.65 | 34.00% | 24.50 | 10.20% | 3.47% | 40.16 | 41.50 | 0.82% | $ 57.70 | $ 45.90 | $ 51.80 | 19.46 | 2.66 | 2.19% | 62.43% | 1.37% | 4.84% | 5.33% | 5.08% | 3.60% | 1.48% |
| Pinnacle West Capital Corporation | PNW | 5.50 | 3.80 | 30.91% | 54.75 | 10.05% | 3.11% | 113.00 | 118.00 | 1.09% | $ 99.80 | $ 81.60 | $ 90.70 | 47.70 | 1.90 | 2.07% | 47.41% | 0.98% | 4.09% | 4.04% | 4.06% | 5.14% | -1.08% |
| PNM Resources, Inc. | PNM | 2.50 | 1.50 | 40.00% | 28.00 | 8.93% | 3.57% | 79.65 | 90.00 | 3.10% | $ 53.00 | $ 39.70 | $ 46.35 | 20.80 | 2.23 | 6.91% | 55.12% | 3.81% | 7.38% | 8.71% | 8.05% | 3.25% | 4.80% |
| Portland General Electric Company | POR | 3.00 | 1.95 | 35.00% | 32.75 | 9.16% | 3.21% | 89.40 | 90.00 | 0.17% | $ 58.40 | $ 44.00 | $ 51.20 | 28.90 | 1.77 | 0.30% | 43.55% | 0.13% | 3.34% | 3.17% | 3.25% | 5.74% | -2.48% |
| Public Service Enterprie Group, Inc. | PEG | 4.25 | 2.40 | 43.53% | 38.00 | 11.18% | 4.87% | 506.00 | 506.00 | 0.00% | $ 63.90 | $ 50.00 | $ 56.95 | 29.65 | 1.92 | 0.00% | 47.94% | 0.00% | 4.87% | 6.14% | 5.50% | 3.53% | 1.98% |
| SEMPRA Energy | SRE | 9.00 | 5.25 | 41.67% | 77.50 | 11.61% | 4.84% | 290.00 | 320.00 | 2.49% | $ 154.50 | $ 106.10 | $ 130.30 | 61.25 | 2.13 | 5.30% | 52.99% | 2.81% | 7.65% | 6.04% | 6.84% | 11.37% | -4.53% |
| Southern Company | SO | 4.00 | 2.86 | 28.50% | 31.50 | 12.70% | 3.62% | 1050.00 | 1080.00 | 0.71% | $ 64.30 | $ 43.30 | $ 53.80 | 26.20 | 2.05 | 1.45% | 51.30% | 0.74% | 4.36% | 3.19% | 3.78% | 6.58% | -2.80% |
| WEC Energy Group, Inc. | WEC | 4.50 | 3.00 | 33.33% | 38.25 | 11.76% | 3.92% | 315.50 | 315.50 | 0.00% | $ 98.20 | $ 67.20 | $ 82.70 | 32.06 | 2.58 | 0.00% | 61.23% | 0.00% | 3.92% | 3.81% | 3.86% | 5.88% | -2.02% |
| Xcel Energy Inc. | XEL | 3.25 | 2.05 | 36.92% | 31.00 | 10.48% | 3.87% | 525.00 | 546.00 | 0.99% | $ 66.10 | $ 47.70 | $ 56.90 | 25.15 | 2.26 | 2.23% | 55.80% | 1.24% | 5.11% | 5.14% | 5.13% | 5.74% | -0.61% |
| | | | Average: | 35.85% | | 10.35% | 0.0371 | | | | | | | | | | | Mean: | 4.90% | 4.63% | 4.77% | 6.37% | -1.60% |
| | | | | | | | | | | | | | | | | | | Median: | 4.85% | 4.38% | 4.72% | 5.50% | -0.85% |

Number of underestimates: 17
Number of overestimates: 9

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.25 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Source: Value Line
[14] Equals [12] / [13]
[15] Equals [9] x [14]
[16] Equals 1 - (1 / [14])
[17] Equals [15] x [16]
[18] Equals [6] + [17]
[19] Source: Rebuttal Exhibit DWD-22 SGR for 2019
[20] Equals Average ([18], [19])

Alternative Bond Yield Plus Risk Premium Analyses

| [1] | [2] | [3] | [4] |
|---|---|---|---|
| 30-Year Treasury Yield | Moody's Utility A Yield | Moody's Utility A Credit Spread | VIX |
| 1.37% | 3.52% | 2.15% | 55.27 |

| | Risk Premium | Return on Equity |
|---|---|---|
| Regression Result - Credit Spread, VIX | 9.61% | 10.98% |

SUMMARY OUTPUT

| *Regression Statistics* | |
|---|---|
| Multiple R | 0.830664 |
| R Square | 0.690002 |
| Adjusted R Square | 0.688757 |
| Standard Error | 0.005294 |
| Observations | 751 |

ANOVA

| | *df* | *SS* | *MS* | *F* | *Significance F* |
|---|---|---|---|---|---|
| Regression | 3 | 0.046591617 | 0.01553054 | 554.2310236 | 1.911E-189 |
| Residual | 747 | 0.020932268 | 2.8022E-05 | | |
| Total | 750 | 0.067523885 | | | |

| | *Coefficients* | *Standard Error* | *t Stat* | *P-value* | *Lower 95%* | *Upper 95%* |
|---|---|---|---|---|---|---|
| Intercept | -0.025834 | 0.002148908 | -12.021801 | 1.47195E-30 | -0.03005236 | -0.021615129 |
| LN(30-Year Treasury) | -0.025051 | 0.0006218 | -40.287632 | 1.809E-189 | -0.02627151 | -0.023830149 |
| Moody's Utility A Credit Spread | 0.197117 | 0.086327424 | 2.28336303 | 0.022688979 | 0.027643617 | 0.366590081 |
| VIX | 0.000185 | 5.44561E-05 | 3.39616011 | 0.000719527 | 7.80364E-05 | 0.000291847 |

Notes:
[1] Source: Bloomberg Professional, Rebuttal Exhibit DWD-5
[2] Source: Bloomberg Professional; 30-day average as of April 17, 2020
[3] Equals [2] - [1]
[4] Source: Bloomberg Professional; 30-day average as of April 17, 2020
[5] Source: S&P Global Market Intelligence
[6] Source: S&P Global Market Intelligence
[7] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[8] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[9] Equals LN[7]
[10] Equals [8] - [7]
[11] Source: Bloomberg Professional, equals 200-trading day average (i.e. lag period) as of April 17, 2020
[12] Equals [6] - [7]

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 11/2/1993 | 10.80% | 6.60% | 7.59% | -2.72 | 0.99% | 12.67 | 4.20% |
| 11/12/1993 | 12.00% | 6.56% | 7.56% | -2.72 | 1.00% | 12.76 | 5.44% |
| 11/26/1993 | 11.00% | 6.52% | 7.53% | -2.73 | 1.01% | 12.85 | 4.48% |
| 12/14/1993 | 10.55% | 6.48% | 7.49% | -2.74 | 1.01% | 12.75 | 4.07% |
| 12/16/1993 | 10.60% | 6.48% | 7.48% | -2.74 | 1.01% | 12.72 | 4.12% |
| 12/21/1993 | 11.30% | 6.47% | 7.48% | -2.74 | 1.01% | 12.66 | 4.83% |
| 1/4/1994 | 10.07% | 6.44% | 7.45% | -2.74 | 1.01% | 12.49 | 3.63% |
| 1/13/1994 | 11.00% | 6.42% | 7.43% | -2.75 | 1.01% | 12.45 | 4.58% |
| 1/21/1994 | 11.00% | 6.40% | 7.41% | -2.75 | 1.01% | 12.39 | 4.60% |
| 1/28/1994 | 11.35% | 6.39% | 7.40% | -2.75 | 1.01% | 12.37 | 4.96% |
| 2/3/1994 | 11.40% | 6.38% | 7.39% | -2.75 | 1.01% | 12.34 | 5.02% |
| 2/17/1994 | 10.60% | 6.36% | 7.37% | -2.76 | 1.02% | 12.38 | 4.24% |
| 2/25/1994 | 11.25% | 6.35% | 7.37% | -2.76 | 1.02% | 12.39 | 4.90% |
| 2/25/1994 | 12.00% | 6.35% | 7.37% | -2.76 | 1.02% | 12.39 | 5.65% |
| 3/1/1994 | 11.00% | 6.35% | 7.37% | -2.76 | 1.02% | 12.40 | 4.65% |
| 3/4/1994 | 11.00% | 6.34% | 7.36% | -2.76 | 1.02% | 12.43 | 4.66% |
| 4/25/1994 | 11.00% | 6.40% | 7.41% | -2.75 | 1.01% | 13.03 | 4.60% |
| 5/10/1994 | 11.75% | 6.44% | 7.45% | -2.74 | 1.01% | 13.20 | 5.31% |
| 5/13/1994 | 10.50% | 6.46% | 7.47% | -2.74 | 1.01% | 13.25 | 4.04% |
| 6/3/1994 | 11.00% | 6.54% | 7.53% | -2.73 | 0.99% | 13.32 | 4.46% |
| 6/27/1994 | 11.40% | 6.65% | 7.63% | -2.71 | 0.98% | 13.42 | 4.75% |
| 8/5/1994 | 12.75% | 6.88% | 7.83% | -2.68 | 0.95% | 13.42 | 5.87% |
| 10/31/1994 | 10.00% | 7.33% | 8.23% | -2.61 | 0.89% | 13.77 | 2.67% |
| 11/9/1994 | 10.85% | 7.40% | 8.29% | -2.60 | 0.89% | 13.94 | 3.45% |
| 11/9/1994 | 10.85% | 7.40% | 8.29% | -2.60 | 0.89% | 13.94 | 3.45% |
| 11/18/1994 | 11.20% | 7.46% | 8.34% | -2.60 | 0.88% | 14.12 | 3.74% |
| 11/22/1994 | 11.60% | 7.47% | 8.35% | -2.59 | 0.88% | 14.14 | 4.13% |
| 11/28/1994 | 11.06% | 7.50% | 8.38% | -2.59 | 0.88% | 14.20 | 3.56% |
| 12/8/1994 | 11.50% | 7.55% | 8.43% | -2.58 | 0.88% | 14.29 | 3.95% |
| 12/8/1994 | 11.70% | 7.55% | 8.43% | -2.58 | 0.88% | 14.29 | 4.15% |
| 12/14/1994 | 10.95% | 7.57% | 8.45% | -2.58 | 0.89% | 14.28 | 3.38% |
| 12/15/1994 | 11.50% | 7.57% | 8.46% | -2.58 | 0.89% | 14.26 | 3.93% |
| 12/19/1994 | 11.50% | 7.58% | 8.47% | -2.58 | 0.89% | 14.24 | 3.92% |
| 12/28/1994 | 12.15% | 7.61% | 8.50% | -2.58 | 0.88% | 14.14 | 4.54% |
| 1/9/1995 | 12.28% | 7.64% | 8.53% | -2.57 | 0.89% | 14.14 | 4.64% |
| 1/31/1995 | 11.00% | 7.69% | 8.58% | -2.57 | 0.89% | 13.71 | 3.31% |
| 2/10/1995 | 12.60% | 7.70% | 8.60% | -2.56 | 0.89% | 13.56 | 4.90% |
| 2/17/1995 | 11.90% | 7.70% | 8.60% | -2.56 | 0.90% | 13.49 | 4.20% |
| 3/9/1995 | 11.50% | 7.72% | 8.61% | -2.56 | 0.90% | 13.37 | 3.78% |
| 3/20/1995 | 12.00% | 7.72% | 8.61% | -2.56 | 0.89% | 13.35 | 4.28% |
| 3/23/1995 | 12.81% | 7.72% | 8.61% | -2.56 | 0.89% | 13.32 | 5.09% |
| 3/29/1995 | 11.60% | 7.72% | 8.62% | -2.56 | 0.90% | 13.31 | 3.88% |
| 4/6/1995 | 11.10% | 7.72% | 8.62% | -2.56 | 0.90% | 13.30 | 3.38% |
| 4/7/1995 | 11.00% | 7.71% | 8.62% | -2.56 | 0.90% | 13.28 | 3.29% |
| 4/19/1995 | 11.00% | 7.70% | 8.61% | -2.56 | 0.91% | 13.20 | 3.30% |
| 5/12/1995 | 11.63% | 7.68% | 8.58% | -2.57 | 0.90% | 13.21 | 3.95% |
| 5/25/1995 | 11.20% | 7.65% | 8.56% | -2.57 | 0.91% | 13.22 | 3.55% |
| 6/9/1995 | 11.25% | 7.60% | 8.52% | -2.58 | 0.92% | 13.26 | 3.65% |
| 6/21/1995 | 12.25% | 7.56% | 8.48% | -2.58 | 0.93% | 13.24 | 4.69% |
| 6/30/1995 | 11.10% | 7.51% | 8.45% | -2.59 | 0.94% | 13.20 | 3.59% |
| 9/11/1995 | 11.30% | 7.20% | 8.17% | -2.63 | 0.97% | 12.48 | 4.10% |
| 9/27/1995 | 11.30% | 7.12% | 8.10% | -2.64 | 0.98% | 12.24 | 4.18% |
| 9/27/1995 | 11.50% | 7.12% | 8.10% | -2.64 | 0.98% | 12.24 | 4.38% |
| 9/27/1995 | 11.75% | 7.12% | 8.10% | -2.64 | 0.98% | 12.24 | 4.63% |
| 9/29/1995 | 11.00% | 7.11% | 8.09% | -2.64 | 0.98% | 12.24 | 3.89% |
| 11/9/1995 | 11.38% | 6.89% | 7.90% | -2.67 | 1.01% | 12.47 | 4.49% |
| 11/9/1995 | 12.36% | 6.89% | 7.90% | -2.67 | 1.01% | 12.47 | 5.47% |
| 11/17/1995 | 11.00% | 6.85% | 7.87% | -2.68 | 1.02% | 12.51 | 4.15% |
| 12/4/1995 | 11.35% | 6.78% | 7.82% | -2.69 | 1.04% | 12.52 | 4.57% |
| 12/11/1995 | 11.40% | 6.74% | 7.79% | -2.70 | 1.05% | 12.52 | 4.66% |
| 12/20/1995 | 11.60% | 6.69% | 7.74% | -2.70 | 1.05% | 12.50 | 4.91% |
| 12/27/1995 | 12.00% | 6.66% | 7.72% | -2.71 | 1.06% | 12.48 | 5.34% |
| 2/5/1996 | 12.25% | 6.48% | 7.58% | -2.74 | 1.11% | 12.63 | 5.77% |
| 3/29/1996 | 10.67% | 6.42% | 7.52% | -2.75 | 1.11% | 13.49 | 4.25% |
| 4/8/1996 | 11.00% | 6.42% | 7.53% | -2.75 | 1.11% | 13.63 | 4.58% |
| 4/11/1996 | 12.59% | 6.43% | 7.53% | -2.74 | 1.11% | 13.74 | 6.16% |
| 4/11/1996 | 12.59% | 6.43% | 7.53% | -2.74 | 1.11% | 13.74 | 6.16% |
| 4/24/1996 | 11.25% | 6.43% | 7.55% | -2.74 | 1.12% | 13.93 | 4.82% |
| 4/30/1996 | 11.00% | 6.43% | 7.55% | -2.74 | 1.12% | 13.99 | 4.57% |
| 5/13/1996 | 11.00% | 6.44% | 7.57% | -2.74 | 1.13% | 14.15 | 4.56% |
| 5/23/1996 | 11.25% | 6.43% | 7.57% | -2.74 | 1.14% | 14.24 | 4.82% |
| 6/25/1996 | 11.25% | 6.48% | 7.60% | -2.74 | 1.12% | 14.73 | 4.77% |
| 6/27/1996 | 11.20% | 6.48% | 7.60% | -2.74 | 1.12% | 14.77 | 4.72% |
| 8/12/1996 | 10.40% | 6.57% | 7.67% | -2.72 | 1.10% | 15.35 | 3.83% |
| 9/27/1996 | 11.00% | 6.71% | 7.76% | -2.70 | 1.05% | 15.98 | 4.29% |
| 10/16/1996 | 12.25% | 6.76% | 7.80% | -2.69 | 1.03% | 16.22 | 5.49% |
| 11/5/1996 | 11.00% | 6.81% | 7.83% | -2.69 | 1.02% | 16.44 | 4.19% |
| 11/26/1996 | 11.30% | 6.83% | 7.85% | -2.68 | 1.01% | 16.58 | 4.47% |
| 12/18/1996 | 11.75% | 6.84% | 7.85% | -2.68 | 1.02% | 16.80 | 4.91% |
| 12/31/1996 | 11.50% | 6.83% | 7.85% | -2.68 | 1.02% | 16.84 | 4.67% |
| 1/3/1997 | 10.70% | 6.83% | 7.85% | -2.68 | 1.02% | 16.85 | 3.87% |
| 2/13/1997 | 11.80% | 6.82% | 7.83% | -2.68 | 1.01% | 17.23 | 4.98% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 2/20/1997 | 11.80% | 6.82% | 7.82% | -2.69 | 1.01% | 17.29 | 4.98% |
| 3/31/1997 | 10.02% | 6.80% | 7.80% | -2.69 | 1.00% | 17.83 | 3.22% |
| 4/2/1997 | 11.65% | 6.80% | 7.80% | -2.69 | 1.00% | 17.86 | 4.85% |
| 4/28/1997 | 11.50% | 6.81% | 7.80% | -2.69 | 0.99% | 18.20 | 4.69% |
| 4/29/1997 | 11.70% | 6.81% | 7.80% | -2.69 | 0.99% | 18.20 | 4.89% |
| 7/17/1997 | 12.00% | 6.77% | 7.75% | -2.69 | 0.97% | 19.04 | 5.23% |
| 12/12/1997 | 11.00% | 6.60% | 7.60% | -2.72 | 1.00% | 22.58 | 4.40% |
| 12/23/1997 | 11.12% | 6.57% | 7.54% | -2.72 | 0.97% | 22.85 | 4.55% |
| 2/2/1998 | 12.75% | 6.39% | 7.47% | -2.75 | 1.08% | 23.45 | 6.36% |
| 3/2/1998 | 11.25% | 6.28% | 7.39% | -2.77 | 1.10% | 23.41 | 4.97% |
| 3/6/1998 | 10.75% | 6.27% | 7.38% | -2.77 | 1.11% | 23.39 | 4.48% |
| 3/20/1998 | 10.50% | 6.22% | 7.34% | -2.78 | 1.12% | 23.36 | 4.28% |
| 4/30/1998 | 12.20% | 6.12% | 7.26% | -2.79 | 1.14% | 23.68 | 6.08% |
| 7/10/1998 | 11.40% | 5.94% | 7.16% | -2.82 | 1.23% | 23.14 | 5.46% |
| 9/15/1998 | 11.90% | 5.78% | 7.09% | -2.85 | 1.31% | 23.80 | 6.12% |
| 11/30/1998 | 12.60% | 5.58% | 7.05% | -2.89 | 1.47% | 26.06 | 7.02% |
| 12/10/1998 | 12.20% | 5.54% | 7.05% | -2.89 | 1.51% | 26.34 | 6.66% |
| 12/17/1998 | 12.10% | 5.52% | 7.04% | -2.90 | 1.52% | 26.58 | 6.58% |
| 2/5/1999 | 10.30% | 5.38% | 7.01% | -2.92 | 1.63% | 27.54 | 4.92% |
| 3/4/1999 | 10.50% | 5.34% | 7.01% | -2.93 | 1.67% | 28.19 | 5.16% |
| 4/6/1999 | 10.94% | 5.32% | 7.03% | -2.93 | 1.71% | 28.47 | 5.62% |
| 7/29/1999 | 10.75% | 5.52% | 7.25% | -2.90 | 1.74% | 25.77 | 5.23% |
| 9/23/1999 | 10.75% | 5.70% | 7.43% | -2.86 | 1.73% | 24.95 | 5.05% |
| 11/17/1999 | 11.10% | 5.90% | 7.63% | -2.83 | 1.73% | 24.31 | 5.20% |
| 1/7/2000 | 11.50% | 6.05% | 7.80% | -2.81 | 1.75% | 23.49 | 5.45% |
| 1/7/2000 | 11.50% | 6.05% | 7.80% | -2.81 | 1.75% | 23.49 | 5.45% |
| 2/17/2000 | 10.60% | 6.17% | 7.95% | -2.78 | 1.77% | 23.35 | 4.43% |
| 3/28/2000 | 11.25% | 6.20% | 8.04% | -2.78 | 1.85% | 22.96 | 5.05% |
| 5/24/2000 | 11.00% | 6.18% | 8.19% | -2.78 | 2.00% | 23.84 | 4.82% |
| 7/18/2000 | 12.20% | 6.16% | 8.27% | -2.79 | 2.11% | 23.36 | 6.04% |
| 9/29/2000 | 11.16% | 6.03% | 8.31% | -2.81 | 2.28% | 22.44 | 5.13% |
| 11/28/2000 | 12.90% | 5.89% | 8.28% | -2.83 | 2.40% | 22.97 | 7.01% |
| 11/30/2000 | 12.10% | 5.88% | 8.28% | -2.83 | 2.40% | 23.03 | 6.22% |
| 1/23/2001 | 11.25% | 5.79% | 8.20% | -2.85 | 2.41% | 23.49 | 5.46% |
| 2/8/2001 | 11.50% | 5.77% | 8.18% | -2.85 | 2.41% | 23.15 | 5.73% |
| 5/8/2001 | 10.75% | 5.62% | 7.97% | -2.88 | 2.35% | 24.39 | 5.13% |
| 6/26/2001 | 11.00% | 5.62% | 7.93% | -2.88 | 2.31% | 24.93 | 5.38% |
| 7/25/2001 | 11.02% | 5.60% | 7.89% | -2.88 | 2.29% | 25.07 | 5.42% |
| 7/25/2001 | 11.02% | 5.60% | 7.89% | -2.88 | 2.29% | 25.07 | 5.42% |
| 7/31/2001 | 11.00% | 5.59% | 7.88% | -2.88 | 2.29% | 24.96 | 5.41% |
| 8/31/2001 | 10.50% | 5.56% | 7.82% | -2.89 | 2.26% | 24.49 | 4.94% |
| 9/7/2001 | 10.75% | 5.55% | 7.80% | -2.89 | 2.25% | 24.53 | 5.20% |
| 9/10/2001 | 11.00% | 5.55% | 7.80% | -2.89 | 2.25% | 24.55 | 5.45% |
| 9/20/2001 | 10.00% | 5.55% | 7.79% | -2.89 | 2.24% | 24.84 | 4.45% |
| 10/24/2001 | 10.30% | 5.54% | 7.77% | -2.89 | 2.23% | 25.69 | 4.76% |
| 11/28/2001 | 10.60% | 5.49% | 7.75% | -2.90 | 2.26% | 26.17 | 5.11% |
| 12/3/2001 | 12.88% | 5.49% | 7.75% | -2.90 | 2.26% | 26.22 | 7.39% |
| 12/20/2001 | 12.50% | 5.50% | 7.76% | -2.90 | 2.26% | 26.14 | 7.00% |
| 1/22/2002 | 10.00% | 5.50% | 7.76% | -2.90 | 2.27% | 25.49 | 4.50% |
| 3/27/2002 | 10.10% | 5.45% | 7.69% | -2.91 | 2.24% | 24.65 | 4.65% |
| 4/22/2002 | 11.80% | 5.45% | 7.67% | -2.91 | 2.22% | 24.49 | 6.35% |
| 5/28/2002 | 10.17% | 5.46% | 7.64% | -2.91 | 2.17% | 24.29 | 4.71% |
| 6/10/2002 | 12.00% | 5.47% | 7.63% | -2.91 | 2.16% | 24.33 | 6.53% |
| 6/18/2002 | 11.16% | 5.48% | 7.62% | -2.90 | 2.15% | 24.42 | 5.68% |
| 6/20/2002 | 11.00% | 5.48% | 7.62% | -2.90 | 2.15% | 24.46 | 5.52% |
| 6/20/2002 | 12.30% | 5.48% | 7.62% | -2.90 | 2.15% | 24.46 | 6.82% |
| 7/15/2002 | 11.00% | 5.48% | 7.60% | -2.90 | 2.13% | 24.08 | 5.52% |
| 9/12/2002 | 12.30% | 5.45% | 7.51% | -2.91 | 2.06% | 25.15 | 6.85% |
| 9/26/2002 | 10.45% | 5.41% | 7.48% | -2.92 | 2.06% | 25.82 | 5.04% |
| 12/4/2002 | 11.55% | 5.29% | 7.36% | -2.94 | 2.07% | 28.03 | 6.26% |
| 12/13/2002 | 11.75% | 5.27% | 7.34% | -2.94 | 2.08% | 28.29 | 6.48% |
| 12/20/2002 | 11.40% | 5.25% | 7.33% | -2.95 | 2.08% | 28.48 | 6.15% |
| 1/8/2003 | 11.10% | 5.19% | 7.29% | -2.96 | 2.10% | 28.93 | 5.91% |
| 1/31/2003 | 12.45% | 5.13% | 7.24% | -2.97 | 2.11% | 29.66 | 7.32% |
| 2/28/2003 | 12.30% | 5.04% | 7.18% | -2.99 | 2.14% | 30.74 | 7.26% |
| 3/6/2003 | 10.75% | 5.02% | 7.17% | -2.99 | 2.14% | 30.99 | 5.73% |
| 3/7/2003 | 9.96% | 5.02% | 7.16% | -2.99 | 2.14% | 31.04 | 4.94% |
| 3/20/2003 | 12.00% | 4.98% | 7.13% | -3.00 | 2.15% | 31.54 | 7.02% |
| 4/3/2003 | 12.00% | 4.95% | 7.10% | -3.00 | 2.14% | 31.74 | 7.05% |
| 4/15/2003 | 11.15% | 4.93% | 7.07% | -3.01 | 2.13% | 31.70 | 6.22% |
| 6/25/2003 | 10.75% | 4.79% | 6.85% | -3.04 | 2.05% | 28.27 | 5.96% |
| 6/26/2003 | 10.75% | 4.79% | 6.84% | -3.04 | 2.05% | 28.19 | 5.96% |
| 7/9/2003 | 9.75% | 4.79% | 6.82% | -3.04 | 2.03% | 27.44 | 4.96% |
| 7/16/2003 | 9.75% | 4.79% | 6.80% | -3.04 | 2.01% | 26.97 | 4.96% |
| 7/25/2003 | 9.50% | 4.79% | 6.79% | -3.04 | 1.99% | 26.27 | 4.71% |
| 8/26/2003 | 10.50% | 4.83% | 6.73% | -3.03 | 1.90% | 24.78 | 5.67% |
| 12/17/2003 | 9.85% | 4.94% | 6.51% | -3.01 | 1.57% | 20.47 | 4.91% |
| 12/17/2003 | 10.70% | 4.94% | 6.51% | -3.01 | 1.57% | 20.47 | 5.76% |
| 12/18/2003 | 11.50% | 4.94% | 6.50% | -3.01 | 1.57% | 20.40 | 6.56% |
| 12/19/2003 | 12.00% | 4.94% | 6.50% | -3.01 | 1.56% | 20.31 | 7.06% |
| 12/19/2003 | 12.00% | 4.94% | 6.50% | -3.01 | 1.56% | 20.31 | 7.06% |
| 12/23/2003 | 10.50% | 4.94% | 6.50% | -3.01 | 1.56% | 20.15 | 5.56% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 1/13/2004 | 12.00% | 4.95% | 6.46% | -3.01 | 1.51% | 19.31 | 7.05% |
| 3/2/2004 | 10.75% | 4.99% | 6.38% | -3.00 | 1.39% | 18.17 | 5.76% |
| 3/26/2004 | 10.25% | 5.02% | 6.35% | -2.99 | 1.33% | 17.96 | 5.23% |
| 4/5/2004 | 11.25% | 5.03% | 6.35% | -2.99 | 1.32% | 17.85 | 6.22% |
| 5/18/2004 | 10.50% | 5.07% | 6.36% | -2.98 | 1.28% | 17.43 | 5.43% |
| 5/25/2004 | 10.25% | 5.07% | 6.35% | -2.98 | 1.28% | 17.36 | 5.18% |
| 5/27/2004 | 10.25% | 5.08% | 6.35% | -2.98 | 1.27% | 17.33 | 5.17% |
| 6/2/2004 | 11.22% | 5.08% | 6.35% | -2.98 | 1.27% | 17.30 | 6.14% |
| 6/30/2004 | 10.50% | 5.10% | 6.32% | -2.98 | 1.22% | 16.96 | 5.40% |
| 6/30/2004 | 10.50% | 5.10% | 6.32% | -2.98 | 1.22% | 16.96 | 5.40% |
| 7/16/2004 | 11.60% | 5.11% | 6.30% | -2.97 | 1.19% | 16.69 | 6.49% |
| 8/25/2004 | 10.25% | 5.10% | 6.27% | -2.98 | 1.17% | 16.53 | 5.15% |
| 9/9/2004 | 10.40% | 5.10% | 6.25% | -2.98 | 1.16% | 16.35 | 5.30% |
| 11/9/2004 | 10.50% | 5.07% | 6.20% | -2.98 | 1.13% | 15.94 | 5.43% |
| 11/23/2004 | 11.00% | 5.06% | 6.19% | -2.98 | 1.13% | 15.75 | 5.94% |
| 12/14/2004 | 10.97% | 5.07% | 6.18% | -2.98 | 1.11% | 15.59 | 5.90% |
| 12/21/2004 | 11.25% | 5.07% | 6.17% | -2.98 | 1.10% | 15.51 | 6.18% |
| 12/21/2004 | 11.50% | 5.07% | 6.17% | -2.98 | 1.10% | 15.51 | 6.43% |
| 12/22/2004 | 10.70% | 5.07% | 6.17% | -2.98 | 1.10% | 15.47 | 5.63% |
| 12/22/2004 | 11.50% | 5.07% | 6.17% | -2.98 | 1.10% | 15.47 | 6.43% |
| 12/29/2004 | 9.85% | 5.08% | 6.17% | -2.98 | 1.10% | 15.30 | 4.77% |
| 1/6/2005 | 10.70% | 5.08% | 6.17% | -2.98 | 1.09% | 15.12 | 5.62% |
| 2/18/2005 | 10.30% | 4.98% | 6.08% | -3.00 | 1.11% | 14.59 | 5.32% |
| 2/25/2005 | 10.50% | 4.96% | 6.06% | -3.00 | 1.11% | 14.46 | 5.54% |
| 3/10/2005 | 11.00% | 4.93% | 6.02% | -3.01 | 1.10% | 14.18 | 6.07% |
| 3/24/2005 | 10.30% | 4.89% | 5.99% | -3.02 | 1.09% | 14.05 | 5.41% |
| 4/4/2005 | 10.00% | 4.87% | 5.97% | -3.02 | 1.09% | 14.02 | 5.13% |
| 4/7/2005 | 10.25% | 4.87% | 5.96% | -3.02 | 1.09% | 14.00 | 5.38% |
| 5/18/2005 | 10.25% | 4.78% | 5.85% | -3.04 | 1.07% | 13.89 | 5.47% |
| 5/25/2005 | 10.75% | 4.76% | 5.84% | -3.04 | 1.07% | 13.75 | 5.99% |
| 5/26/2005 | 9.75% | 4.76% | 5.83% | -3.04 | 1.07% | 13.71 | 4.99% |
| 6/1/2005 | 9.75% | 4.75% | 5.82% | -3.05 | 1.07% | 13.64 | 5.00% |
| 7/19/2005 | 11.50% | 4.64% | 5.72% | -3.07 | 1.08% | 13.17 | 6.86% |
| 8/5/2005 | 11.75% | 4.62% | 5.70% | -3.07 | 1.07% | 12.94 | 7.13% |
| 8/15/2005 | 10.13% | 4.61% | 5.68% | -3.08 | 1.07% | 12.84 | 5.52% |
| 9/28/2005 | 10.00% | 4.54% | 5.61% | -3.09 | 1.07% | 12.77 | 5.46% |
| 10/4/2005 | 10.75% | 4.53% | 5.60% | -3.09 | 1.07% | 12.78 | 6.22% |
| 12/12/2005 | 11.00% | 4.55% | 5.63% | -3.09 | 1.08% | 12.97 | 6.45% |
| 12/13/2005 | 10.75% | 4.55% | 5.63% | -3.09 | 1.08% | 12.96 | 6.20% |
| 12/21/2005 | 10.29% | 4.54% | 5.63% | -3.09 | 1.09% | 12.91 | 5.75% |
| 12/21/2005 | 10.40% | 4.54% | 5.63% | -3.09 | 1.09% | 12.91 | 5.86% |
| 12/22/2005 | 11.00% | 4.54% | 5.63% | -3.09 | 1.09% | 12.90 | 6.46% |
| 12/22/2005 | 11.15% | 4.54% | 5.63% | -3.09 | 1.09% | 12.90 | 6.61% |
| 12/28/2005 | 10.00% | 4.54% | 5.63% | -3.09 | 1.09% | 12.87 | 5.46% |
| 12/28/2005 | 10.00% | 4.54% | 5.63% | -3.09 | 1.09% | 12.87 | 5.46% |
| 1/5/2006 | 11.00% | 4.53% | 5.62% | -3.09 | 1.09% | 12.82 | 6.47% |
| 1/27/2006 | 9.75% | 4.52% | 5.62% | -3.10 | 1.10% | 12.72 | 5.23% |
| 3/3/2006 | 10.39% | 4.53% | 5.65% | -3.09 | 1.12% | 12.39 | 5.86% |
| 4/17/2006 | 10.20% | 4.62% | 5.75% | -3.08 | 1.14% | 12.34 | 5.58% |
| 4/26/2006 | 10.60% | 4.64% | 5.78% | -3.07 | 1.14% | 12.34 | 5.96% |
| 5/17/2006 | 11.60% | 4.69% | 5.85% | -3.06 | 1.15% | 12.47 | 6.91% |
| 6/6/2006 | 10.00% | 4.75% | 5.90% | -3.05 | 1.16% | 12.72 | 5.25% |
| 6/27/2006 | 10.75% | 4.80% | 5.98% | -3.04 | 1.18% | 13.07 | 5.95% |
| 7/6/2006 | 10.20% | 4.83% | 6.01% | -3.03 | 1.18% | 13.12 | 5.37% |
| 7/24/2006 | 9.60% | 4.86% | 6.05% | -3.02 | 1.19% | 13.29 | 4.74% |
| 7/26/2006 | 10.50% | 4.86% | 6.06% | -3.02 | 1.20% | 13.29 | 5.64% |
| 7/28/2006 | 10.05% | 4.87% | 6.06% | -3.02 | 1.20% | 13.27 | 5.18% |
| 8/23/2006 | 9.55% | 4.89% | 6.10% | -3.02 | 1.21% | 13.20 | 4.66% |
| 9/1/2006 | 10.54% | 4.90% | 6.10% | -3.02 | 1.21% | 13.19 | 5.64% |
| 9/14/2006 | 10.00% | 4.91% | 6.11% | -3.01 | 1.21% | 13.25 | 5.09% |
| 10/6/2006 | 9.67% | 4.92% | 6.12% | -3.01 | 1.20% | 13.30 | 4.75% |
| 11/21/2006 | 10.08% | 4.95% | 6.15% | -3.01 | 1.19% | 13.12 | 5.13% |
| 11/21/2006 | 10.08% | 4.95% | 6.15% | -3.01 | 1.19% | 13.12 | 5.13% |
| 11/21/2006 | 10.12% | 4.95% | 6.15% | -3.01 | 1.19% | 13.12 | 5.17% |
| 12/1/2006 | 10.25% | 4.96% | 6.14% | -3.00 | 1.19% | 13.07 | 5.29% |
| 12/1/2006 | 10.50% | 4.96% | 6.14% | -3.00 | 1.19% | 13.07 | 5.54% |
| 12/7/2006 | 10.75% | 4.96% | 6.14% | -3.00 | 1.19% | 13.06 | 5.79% |
| 12/21/2006 | 10.90% | 4.95% | 6.14% | -3.00 | 1.18% | 12.98 | 5.95% |
| 12/21/2006 | 11.25% | 4.95% | 6.14% | -3.00 | 1.18% | 12.98 | 6.30% |
| 12/22/2006 | 10.25% | 4.95% | 6.14% | -3.00 | 1.18% | 12.98 | 5.30% |
| 1/5/2007 | 10.00% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.05% |
| 1/11/2007 | 10.10% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.15% |
| 1/11/2007 | 10.10% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.15% |
| 1/11/2007 | 10.90% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.95% |
| 1/12/2007 | 10.10% | 4.95% | 6.13% | -3.01 | 1.18% | 12.98 | 5.15% |
| 1/13/2007 | 10.40% | 4.95% | 6.13% | -3.01 | 1.18% | 12.97 | 5.45% |
| 1/19/2007 | 10.80% | 4.94% | 6.13% | -3.01 | 1.19% | 12.96 | 5.86% |
| 3/21/2007 | 11.35% | 4.86% | 6.03% | -3.02 | 1.16% | 12.81 | 6.49% |
| 3/22/2007 | 9.75% | 4.86% | 6.03% | -3.02 | 1.16% | 12.78 | 4.89% |
| 5/15/2007 | 10.00% | 4.81% | 5.94% | -3.04 | 1.13% | 12.22 | 5.19% |
| 5/17/2007 | 10.25% | 4.80% | 5.94% | -3.04 | 1.13% | 12.21 | 5.45% |
| 5/17/2007 | 10.25% | 4.80% | 5.94% | -3.04 | 1.13% | 12.21 | 5.45% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 5/22/2007 | 10.20% | 4.80% | 5.94% | -3.04 | 1.13% | 12.19 | 5.40% |
| 5/22/2007 | 10.50% | 4.80% | 5.94% | -3.04 | 1.13% | 12.19 | 5.70% |
| 5/23/2007 | 10.70% | 4.80% | 5.94% | -3.04 | 1.13% | 12.18 | 5.90% |
| 5/25/2007 | 9.67% | 4.80% | 5.93% | -3.04 | 1.13% | 12.16 | 4.87% |
| 6/15/2007 | 9.90% | 4.82% | 5.94% | -3.03 | 1.12% | 12.27 | 5.08% |
| 6/21/2007 | 10.20% | 4.83% | 5.94% | -3.03 | 1.12% | 12.30 | 5.37% |
| 6/22/2007 | 10.50% | 4.83% | 5.94% | -3.03 | 1.12% | 12.31 | 5.67% |
| 6/28/2007 | 10.75% | 4.84% | 5.95% | -3.03 | 1.11% | 12.38 | 5.91% |
| 7/12/2007 | 9.67% | 4.86% | 5.96% | -3.02 | 1.11% | 12.56 | 4.81% |
| 7/19/2007 | 10.00% | 4.87% | 5.97% | -3.02 | 1.11% | 12.65 | 5.13% |
| 7/19/2007 | 10.00% | 4.87% | 5.97% | -3.02 | 1.11% | 12.65 | 5.13% |
| 8/15/2007 | 10.40% | 4.88% | 5.99% | -3.02 | 1.12% | 13.76 | 5.52% |
| 10/9/2007 | 10.00% | 4.91% | 6.07% | -3.01 | 1.16% | 15.94 | 5.09% |
| 10/17/2007 | 9.10% | 4.91% | 6.08% | -3.01 | 1.17% | 16.15 | 4.19% |
| 10/31/2007 | 9.96% | 4.90% | 6.09% | -3.02 | 1.18% | 16.62 | 5.06% |
| 11/29/2007 | 10.90% | 4.87% | 6.08% | -3.02 | 1.21% | 18.14 | 6.03% |
| 12/6/2007 | 10.75% | 4.86% | 6.09% | -3.02 | 1.22% | 18.45 | 5.89% |
| 12/13/2007 | 9.96% | 4.86% | 6.10% | -3.02 | 1.24% | 18.60 | 5.10% |
| 12/14/2007 | 10.70% | 4.86% | 6.10% | -3.02 | 1.24% | 18.62 | 5.84% |
| 12/14/2007 | 10.80% | 4.86% | 6.10% | -3.02 | 1.24% | 18.62 | 5.94% |
| 12/19/2007 | 10.20% | 4.86% | 6.11% | -3.02 | 1.25% | 18.74 | 5.34% |
| 12/20/2007 | 10.20% | 4.86% | 6.11% | -3.03 | 1.25% | 18.77 | 5.34% |
| 12/20/2007 | 11.00% | 4.86% | 6.11% | -3.03 | 1.25% | 18.77 | 6.14% |
| 12/28/2007 | 10.25% | 4.85% | 6.12% | -3.03 | 1.27% | 18.84 | 5.40% |
| 12/31/2007 | 11.25% | 4.85% | 6.12% | -3.03 | 1.27% | 18.88 | 6.40% |
| 1/8/2008 | 10.75% | 4.83% | 6.12% | -3.03 | 1.29% | 19.16 | 5.92% |
| 1/17/2008 | 10.75% | 4.81% | 6.12% | -3.03 | 1.31% | 19.51 | 5.94% |
| 1/28/2008 | 9.40% | 4.80% | 6.12% | -3.04 | 1.33% | 19.99 | 4.60% |
| 1/30/2008 | 10.00% | 4.79% | 6.12% | -3.04 | 1.33% | 20.14 | 5.21% |
| 1/31/2008 | 10.71% | 4.79% | 6.12% | -3.04 | 1.34% | 20.21 | 5.92% |
| 2/29/2008 | 10.25% | 4.75% | 6.15% | -3.05 | 1.41% | 21.45 | 5.50% |
| 3/12/2008 | 10.25% | 4.73% | 6.16% | -3.05 | 1.44% | 21.99 | 5.52% |
| 3/25/2008 | 9.10% | 4.68% | 6.16% | -3.06 | 1.48% | 22.55 | 4.42% |
| 4/22/2008 | 10.25% | 4.60% | 6.16% | -3.08 | 1.56% | 23.32 | 5.65% |
| 4/24/2008 | 10.10% | 4.60% | 6.16% | -3.08 | 1.56% | 23.35 | 5.50% |
| 5/1/2008 | 10.70% | 4.58% | 6.16% | -3.08 | 1.57% | 23.46 | 6.12% |
| 5/19/2008 | 11.00% | 4.56% | 6.16% | -3.09 | 1.60% | 23.32 | 6.44% |
| 5/27/2008 | 10.00% | 4.55% | 6.16% | -3.09 | 1.61% | 23.18 | 5.45% |
| 6/10/2008 | 10.70% | 4.54% | 6.17% | -3.09 | 1.62% | 22.89 | 6.16% |
| 6/27/2008 | 10.50% | 4.54% | 6.18% | -3.09 | 1.65% | 22.73 | 5.96% |
| 6/27/2008 | 11.04% | 4.54% | 6.18% | -3.09 | 1.65% | 22.73 | 6.50% |
| 7/10/2008 | 10.43% | 4.52% | 6.19% | -3.10 | 1.66% | 22.88 | 5.91% |
| 7/16/2008 | 9.40% | 4.51% | 6.19% | -3.10 | 1.67% | 23.08 | 4.89% |
| 7/30/2008 | 10.80% | 4.51% | 6.20% | -3.10 | 1.69% | 23.33 | 6.29% |
| 7/31/2008 | 10.70% | 4.51% | 6.20% | -3.10 | 1.70% | 23.34 | 6.19% |
| 8/11/2008 | 10.25% | 4.50% | 6.22% | -3.10 | 1.71% | 23.37 | 5.75% |
| 8/26/2008 | 10.18% | 4.50% | 6.24% | -3.10 | 1.74% | 23.23 | 5.68% |
| 9/10/2008 | 10.30% | 4.50% | 6.25% | -3.10 | 1.75% | 23.01 | 5.80% |
| 9/24/2008 | 10.65% | 4.48% | 6.28% | -3.11 | 1.79% | 23.46 | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.28% | -3.11 | 1.79% | 23.46 | 6.17% |
| 9/24/2008 | 10.65% | 4.48% | 6.28% | -3.11 | 1.79% | 23.46 | 6.17% |
| 9/30/2008 | 10.20% | 4.47% | 6.29% | -3.11 | 1.82% | 23.77 | 5.73% |
| 10/8/2008 | 10.15% | 4.46% | 6.31% | -3.11 | 1.85% | 24.61 | 5.69% |
| 11/13/2008 | 10.55% | 4.45% | 6.52% | -3.11 | 2.08% | 29.58 | 6.10% |
| 11/17/2008 | 10.20% | 4.44% | 6.54% | -3.11 | 2.10% | 29.98 | 5.76% |
| 12/1/2008 | 10.25% | 4.39% | 6.59% | -3.12 | 2.20% | 31.79 | 5.86% |
| 12/23/2008 | 11.00% | 4.27% | 6.62% | -3.15 | 2.35% | 34.13 | 6.73% |
| 12/29/2008 | 10.00% | 4.24% | 6.62% | -3.16 | 2.38% | 34.34 | 5.76% |
| 12/29/2008 | 10.20% | 4.24% | 6.62% | -3.16 | 2.38% | 34.34 | 5.96% |
| 12/31/2008 | 10.75% | 4.22% | 6.62% | -3.17 | 2.40% | 34.47 | 6.53% |
| 1/14/2009 | 10.50% | 4.15% | 6.63% | -3.18 | 2.48% | 35.25 | 6.35% |
| 1/21/2009 | 10.50% | 4.11% | 6.63% | -3.19 | 2.51% | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.63% | -3.19 | 2.51% | 35.81 | 6.39% |
| 1/21/2009 | 10.50% | 4.11% | 6.63% | -3.19 | 2.51% | 35.81 | 6.39% |
| 1/27/2009 | 10.76% | 4.09% | 6.63% | -3.20 | 2.54% | 36.26 | 6.67% |
| 1/30/2009 | 10.50% | 4.07% | 6.64% | -3.20 | 2.56% | 36.58 | 6.43% |
| 2/4/2009 | 8.75% | 4.06% | 6.64% | -3.20 | 2.58% | 36.94 | 4.69% |
| 3/4/2009 | 10.50% | 3.96% | 6.64% | -3.23 | 2.68% | 39.59 | 6.54% |
| 3/12/2009 | 11.50% | 3.93% | 6.64% | -3.24 | 2.71% | 40.42 | 7.57% |
| 4/2/2009 | 11.10% | 3.85% | 6.65% | -3.26 | 2.80% | 42.04 | 7.25% |
| 4/21/2009 | 10.61% | 3.80% | 6.66% | -3.27 | 2.86% | 42.91 | 6.81% |
| 4/24/2009 | 10.00% | 3.78% | 6.66% | -3.27 | 2.87% | 43.10 | 6.22% |
| 4/30/2009 | 11.25% | 3.77% | 6.66% | -3.28 | 2.89% | 43.29 | 7.48% |
| 5/4/2009 | 10.74% | 3.77% | 6.67% | -3.28 | 2.90% | 43.40 | 6.97% |
| 5/20/2009 | 10.25% | 3.74% | 6.66% | -3.29 | 2.92% | 43.96 | 6.51% |
| 5/28/2009 | 10.50% | 3.74% | 6.67% | -3.29 | 2.93% | 44.24 | 6.76% |
| 6/22/2009 | 10.00% | 3.76% | 6.66% | -3.28 | 2.90% | 45.01 | 6.24% |
| 6/24/2009 | 10.80% | 3.76% | 6.66% | -3.28 | 2.90% | 45.06 | 7.04% |
| 7/8/2009 | 10.63% | 3.76% | 6.65% | -3.28 | 2.88% | 44.95 | 6.87% |
| 7/17/2009 | 10.50% | 3.77% | 6.62% | -3.28 | 2.84% | 44.55 | 6.73% |
| 8/31/2009 | 10.25% | 3.82% | 6.33% | -3.27 | 2.51% | 38.96 | 6.43% |
| 10/14/2009 | 10.70% | 4.02% | 6.13% | -3.21 | 2.11% | 33.90 | 6.68% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 10/23/2009 | 10.88% | 4.06% | 6.10% | -3.20 | 2.04% | 33.22 | 6.82% |
| 11/2/2009 | 10.70% | 4.10% | 6.08% | -3.20 | 1.99% | 32.57 | 6.60% |
| 11/3/2009 | 10.70% | 4.10% | 6.08% | -3.19 | 1.98% | 32.48 | 6.60% |
| 11/24/2009 | 10.25% | 4.16% | 6.02% | -3.18 | 1.87% | 30.89 | 6.09% |
| 11/25/2009 | 10.75% | 4.16% | 6.02% | -3.18 | 1.86% | 30.79 | 6.59% |
| 11/30/2009 | 10.35% | 4.17% | 6.02% | -3.18 | 1.85% | 30.58 | 6.18% |
| 12/3/2009 | 10.50% | 4.18% | 6.01% | -3.18 | 1.83% | 30.18 | 6.32% |
| 12/7/2009 | 10.70% | 4.19% | 6.00% | -3.17 | 1.81% | 29.90 | 6.51% |
| 12/16/2009 | 10.90% | 4.22% | 5.98% | -3.17 | 1.76% | 28.98 | 6.68% |
| 12/16/2009 | 11.00% | 4.22% | 5.98% | -3.17 | 1.76% | 28.98 | 6.78% |
| 12/18/2009 | 10.40% | 4.22% | 5.98% | -3.16 | 1.75% | 28.70 | 6.18% |
| 12/18/2009 | 10.40% | 4.22% | 5.98% | -3.16 | 1.75% | 28.70 | 6.18% |
| 12/22/2009 | 10.20% | 4.23% | 5.97% | -3.16 | 1.74% | 28.46 | 5.97% |
| 12/22/2009 | 10.40% | 4.23% | 5.97% | -3.16 | 1.74% | 28.46 | 6.17% |
| 12/22/2009 | 10.40% | 4.23% | 5.97% | -3.16 | 1.74% | 28.46 | 6.17% |
| 12/30/2009 | 10.00% | 4.26% | 5.96% | -3.16 | 1.69% | 27.91 | 5.74% |
| 1/4/2010 | 10.80% | 4.28% | 5.95% | -3.15 | 1.67% | 27.67 | 6.52% |
| 1/11/2010 | 11.00% | 4.31% | 5.94% | -3.15 | 1.63% | 27.09 | 6.69% |
| 1/26/2010 | 10.13% | 4.35% | 5.90% | -3.13 | 1.55% | 26.08 | 5.78% |
| 1/27/2010 | 10.40% | 4.36% | 5.90% | -3.13 | 1.54% | 26.01 | 6.04% |
| 1/27/2010 | 10.40% | 4.36% | 5.90% | -3.13 | 1.54% | 26.01 | 6.04% |
| 1/27/2010 | 10.70% | 4.36% | 5.90% | -3.13 | 1.54% | 26.01 | 6.34% |
| 2/9/2010 | 9.80% | 4.38% | 5.86% | -3.13 | 1.48% | 25.43 | 5.42% |
| 2/18/2010 | 10.60% | 4.40% | 5.85% | -3.12 | 1.45% | 25.05 | 6.20% |
| 2/24/2010 | 10.18% | 4.41% | 5.83% | -3.12 | 1.43% | 24.80 | 5.77% |
| 3/2/2010 | 9.63% | 4.41% | 5.82% | -3.12 | 1.41% | 24.54 | 5.22% |
| 3/4/2010 | 10.50% | 4.41% | 5.82% | -3.12 | 1.40% | 24.43 | 6.09% |
| 3/5/2010 | 10.50% | 4.41% | 5.81% | -3.12 | 1.40% | 24.37 | 6.09% |
| 3/11/2010 | 11.90% | 4.42% | 5.80% | -3.12 | 1.39% | 24.10 | 7.48% |
| 3/17/2010 | 10.00% | 4.41% | 5.79% | -3.12 | 1.37% | 23.85 | 5.59% |
| 3/25/2010 | 10.15% | 4.42% | 5.77% | -3.12 | 1.35% | 23.47 | 5.73% |
| 4/2/2010 | 10.10% | 4.43% | 5.76% | -3.12 | 1.33% | 22.82 | 5.67% |
| 4/27/2010 | 10.00% | 4.46% | 5.74% | -3.11 | 1.29% | 22.16 | 5.54% |
| 4/29/2010 | 9.90% | 4.46% | 5.74% | -3.11 | 1.28% | 22.11 | 5.44% |
| 4/29/2010 | 10.06% | 4.46% | 5.74% | -3.11 | 1.28% | 22.11 | 5.60% |
| 4/29/2010 | 10.26% | 4.46% | 5.74% | -3.11 | 1.28% | 22.11 | 5.80% |
| 5/12/2010 | 10.30% | 4.45% | 5.72% | -3.11 | 1.26% | 22.26 | 5.85% |
| 5/12/2010 | 10.30% | 4.45% | 5.72% | -3.11 | 1.26% | 22.26 | 5.85% |
| 5/28/2010 | 10.10% | 4.44% | 5.70% | -3.11 | 1.25% | 22.81 | 5.66% |
| 5/28/2010 | 10.20% | 4.44% | 5.70% | -3.11 | 1.25% | 22.81 | 5.76% |
| 6/7/2010 | 10.30% | 4.44% | 5.69% | -3.11 | 1.25% | 23.00 | 5.86% |
| 6/16/2010 | 10.00% | 4.44% | 5.69% | -3.11 | 1.25% | 23.16 | 5.56% |
| 6/28/2010 | 9.67% | 4.43% | 5.68% | -3.12 | 1.25% | 23.19 | 5.24% |
| 6/28/2010 | 10.50% | 4.43% | 5.68% | -3.12 | 1.25% | 23.19 | 6.07% |
| 6/30/2010 | 9.40% | 4.43% | 5.68% | -3.12 | 1.25% | 23.30 | 4.97% |
| 7/1/2010 | 10.25% | 4.43% | 5.68% | -3.12 | 1.25% | 23.34 | 5.82% |
| 7/15/2010 | 10.53% | 4.43% | 5.67% | -3.12 | 1.24% | 23.43 | 6.10% |
| 7/15/2010 | 10.70% | 4.43% | 5.67% | -3.12 | 1.24% | 23.43 | 6.27% |
| 7/30/2010 | 10.70% | 4.41% | 5.66% | -3.12 | 1.24% | 23.39 | 6.29% |
| 8/4/2010 | 10.50% | 4.41% | 5.65% | -3.12 | 1.24% | 23.40 | 6.09% |
| 8/6/2010 | 9.83% | 4.41% | 5.65% | -3.12 | 1.24% | 23.41 | 5.42% |
| 8/25/2010 | 9.90% | 4.37% | 5.60% | -3.13 | 1.23% | 23.38 | 5.53% |
| 9/3/2010 | 10.60% | 4.35% | 5.58% | -3.14 | 1.23% | 23.44 | 6.25% |
| 9/14/2010 | 10.70% | 4.33% | 5.56% | -3.14 | 1.23% | 23.46 | 6.37% |
| 9/16/2010 | 10.00% | 4.32% | 5.56% | -3.14 | 1.23% | 23.44 | 5.68% |
| 9/16/2010 | 10.00% | 4.32% | 5.56% | -3.14 | 1.23% | 23.44 | 5.68% |
| 9/30/2010 | 9.75% | 4.28% | 5.52% | -3.15 | 1.23% | 23.47 | 5.47% |
| 10/14/2010 | 10.35% | 4.24% | 5.48% | -3.16 | 1.24% | 23.50 | 6.11% |
| 10/28/2010 | 10.70% | 4.21% | 5.45% | -3.17 | 1.24% | 23.55 | 6.49% |
| 11/2/2010 | 10.38% | 4.20% | 5.44% | -3.17 | 1.24% | 23.60 | 6.18% |
| 11/4/2010 | 10.70% | 4.19% | 5.43% | -3.17 | 1.24% | 23.54 | 6.51% |
| 11/19/2010 | 10.20% | 4.17% | 5.42% | -3.18 | 1.24% | 23.28 | 6.03% |
| 11/22/2010 | 10.00% | 4.17% | 5.41% | -3.18 | 1.24% | 23.24 | 5.83% |
| 12/1/2010 | 10.13% | 4.16% | 5.40% | -3.18 | 1.24% | 23.21 | 5.97% |
| 12/6/2010 | 9.86% | 4.15% | 5.39% | -3.18 | 1.24% | 23.18 | 5.71% |
| 12/9/2010 | 10.25% | 4.15% | 5.38% | -3.18 | 1.24% | 23.14 | 6.10% |
| 12/13/2010 | 10.70% | 4.15% | 5.38% | -3.18 | 1.24% | 23.13 | 6.55% |
| 12/14/2010 | 10.13% | 4.15% | 5.38% | -3.18 | 1.24% | 23.12 | 5.98% |
| 12/15/2010 | 10.44% | 4.15% | 5.38% | -3.18 | 1.24% | 23.12 | 6.29% |
| 12/17/2010 | 10.00% | 4.14% | 5.38% | -3.18 | 1.23% | 23.11 | 5.86% |
| 12/20/2010 | 10.60% | 4.14% | 5.38% | -3.18 | 1.23% | 23.10 | 6.46% |
| 12/21/2010 | 10.30% | 4.14% | 5.38% | -3.18 | 1.23% | 23.09 | 6.16% |
| 12/27/2010 | 9.90% | 4.14% | 5.37% | -3.18 | 1.23% | 23.07 | 5.76% |
| 12/29/2010 | 11.15% | 4.14% | 5.37% | -3.19 | 1.23% | 23.07 | 7.01% |
| 1/5/2011 | 10.15% | 4.13% | 5.36% | -3.19 | 1.23% | 23.08 | 6.02% |
| 1/12/2011 | 10.30% | 4.12% | 5.35% | -3.19 | 1.23% | 23.07 | 6.18% |
| 1/13/2011 | 10.30% | 4.12% | 5.35% | -3.19 | 1.23% | 23.06 | 6.18% |
| 1/18/2011 | 10.00% | 4.12% | 5.35% | -3.19 | 1.23% | 23.05 | 5.88% |
| 1/20/2011 | 9.30% | 4.12% | 5.34% | -3.19 | 1.23% | 23.06 | 5.18% |
| 1/20/2011 | 10.13% | 4.12% | 5.34% | -3.19 | 1.23% | 23.06 | 6.01% |
| 1/31/2011 | 9.60% | 4.11% | 5.33% | -3.19 | 1.22% | 23.12 | 5.49% |
| 2/3/2011 | 10.00% | 4.11% | 5.33% | -3.19 | 1.22% | 23.13 | 5.89% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 2/25/2011 | 10.00% | 4.14% | 5.34% | -3.18 | 1.20% | 22.58 | 5.86% |
| 3/25/2011 | 9.80% | 4.18% | 5.34% | -3.18 | 1.17% | 21.29 | 5.62% |
| 3/30/2011 | 10.00% | 4.18% | 5.35% | -3.17 | 1.16% | 21.16 | 5.82% |
| 4/12/2011 | 10.00% | 4.21% | 5.35% | -3.17 | 1.14% | 20.69 | 5.79% |
| 4/25/2011 | 10.74% | 4.23% | 5.37% | -3.16 | 1.13% | 20.17 | 6.51% |
| 4/26/2011 | 9.67% | 4.24% | 5.37% | -3.16 | 1.13% | 20.13 | 5.43% |
| 4/27/2011 | 10.40% | 4.24% | 5.37% | -3.16 | 1.13% | 20.08 | 6.16% |
| 5/4/2011 | 10.00% | 4.25% | 5.37% | -3.16 | 1.13% | 19.84 | 5.75% |
| 5/4/2011 | 10.00% | 4.25% | 5.37% | -3.16 | 1.13% | 19.84 | 5.75% |
| 5/24/2011 | 10.50% | 4.27% | 5.38% | -3.15 | 1.11% | 19.44 | 6.23% |
| 6/8/2011 | 10.75% | 4.30% | 5.39% | -3.15 | 1.09% | 19.02 | 6.45% |
| 6/16/2011 | 9.20% | 4.32% | 5.40% | -3.14 | 1.09% | 18.83 | 4.88% |
| 6/17/2011 | 9.95% | 4.32% | 5.40% | -3.14 | 1.09% | 18.83 | 5.63% |
| 7/13/2011 | 10.20% | 4.37% | 5.43% | -3.13 | 1.06% | 18.48 | 5.83% |
| 8/1/2011 | 9.20% | 4.39% | 5.44% | -3.13 | 1.05% | 18.46 | 4.81% |
| 8/8/2011 | 10.00% | 4.38% | 5.43% | -3.13 | 1.05% | 18.77 | 5.62% |
| 8/11/2011 | 10.00% | 4.38% | 5.42% | -3.13 | 1.05% | 19.05 | 5.62% |
| 8/12/2011 | 10.35% | 4.38% | 5.42% | -3.13 | 1.05% | 19.13 | 5.97% |
| 8/19/2011 | 10.25% | 4.36% | 5.41% | -3.13 | 1.05% | 19.53 | 5.89% |
| 9/2/2011 | 12.88% | 4.32% | 5.37% | -3.14 | 1.05% | 20.31 | 8.56% |
| 9/22/2011 | 10.00% | 4.24% | 5.31% | -3.16 | 1.07% | 21.34 | 5.76% |
| 10/12/2011 | 10.30% | 4.14% | 5.23% | -3.19 | 1.09% | 22.82 | 6.16% |
| 10/20/2011 | 10.50% | 4.10% | 5.20% | -3.19 | 1.10% | 23.27 | 6.40% |
| 11/30/2011 | 10.90% | 3.87% | 5.02% | -3.25 | 1.15% | 25.28 | 7.03% |
| 11/30/2011 | 10.90% | 3.87% | 5.02% | -3.25 | 1.15% | 25.28 | 7.03% |
| 12/14/2011 | 10.00% | 3.79% | 4.96% | -3.27 | 1.17% | 25.67 | 6.21% |
| 12/14/2011 | 10.30% | 3.79% | 4.96% | -3.27 | 1.17% | 25.67 | 6.51% |
| 12/20/2011 | 10.20% | 3.76% | 4.93% | -3.28 | 1.17% | 25.76 | 6.44% |
| 12/21/2011 | 10.20% | 3.75% | 4.93% | -3.28 | 1.17% | 25.76 | 6.45% |
| 12/22/2011 | 9.90% | 3.75% | 4.92% | -3.28 | 1.17% | 25.77 | 6.15% |
| 12/22/2011 | 10.40% | 3.75% | 4.92% | -3.28 | 1.17% | 25.77 | 6.65% |
| 12/23/2011 | 10.19% | 3.74% | 4.92% | -3.29 | 1.18% | 25.76 | 6.45% |
| 1/25/2012 | 10.50% | 3.57% | 4.79% | -3.33 | 1.23% | 25.89 | 6.93% |
| 1/27/2012 | 10.50% | 3.55% | 4.78% | -3.34 | 1.23% | 25.91 | 6.95% |
| 2/15/2012 | 10.20% | 3.47% | 4.70% | -3.36 | 1.23% | 26.12 | 6.73% |
| 2/23/2012 | 9.90% | 3.43% | 4.68% | -3.37 | 1.24% | 26.14 | 6.47% |
| 2/27/2012 | 10.25% | 3.42% | 4.67% | -3.37 | 1.25% | 26.15 | 6.83% |
| 2/29/2012 | 10.40% | 3.41% | 4.66% | -3.38 | 1.25% | 26.16 | 6.99% |
| 3/29/2012 | 10.37% | 3.31% | 4.57% | -3.41 | 1.26% | 25.99 | 7.06% |
| 4/4/2012 | 10.00% | 3.29% | 4.56% | -3.41 | 1.27% | 25.89 | 6.71% |
| 4/26/2012 | 10.00% | 3.20% | 4.48% | -3.44 | 1.28% | 25.91 | 6.80% |
| 5/2/2012 | 10.00% | 3.18% | 4.47% | -3.45 | 1.29% | 25.85 | 6.82% |
| 5/7/2012 | 9.80% | 3.16% | 4.45% | -3.45 | 1.29% | 25.85 | 6.64% |
| 5/15/2012 | 10.00% | 3.14% | 4.42% | -3.46 | 1.28% | 25.79 | 6.86% |
| 5/29/2012 | 10.05% | 3.11% | 4.40% | -3.47 | 1.29% | 25.23 | 6.94% |
| 6/7/2012 | 10.30% | 3.07% | 4.38% | -3.48 | 1.30% | 24.77 | 7.23% |
| 6/14/2012 | 9.40% | 3.06% | 4.36% | -3.49 | 1.30% | 24.45 | 6.34% |
| 6/15/2012 | 10.40% | 3.06% | 4.36% | -3.49 | 1.30% | 24.40 | 7.34% |
| 6/18/2012 | 9.60% | 3.05% | 4.36% | -3.49 | 1.30% | 24.33 | 6.55% |
| 6/19/2012 | 9.25% | 3.05% | 4.35% | -3.49 | 1.30% | 24.25 | 6.20% |
| 6/26/2012 | 10.10% | 3.04% | 4.34% | -3.49 | 1.30% | 23.82 | 7.06% |
| 6/29/2012 | 10.00% | 3.04% | 4.34% | -3.49 | 1.30% | 23.58 | 6.96% |
| 7/9/2012 | 10.20% | 3.03% | 4.32% | -3.50 | 1.30% | 23.14 | 7.17% |
| 7/16/2012 | 9.80% | 3.02% | 4.31% | -3.50 | 1.29% | 22.59 | 6.78% |
| 7/20/2012 | 9.31% | 3.01% | 4.30% | -3.50 | 1.30% | 22.07 | 6.30% |
| 7/20/2012 | 9.81% | 3.01% | 4.30% | -3.50 | 1.30% | 22.07 | 6.80% |
| 9/13/2012 | 9.80% | 2.94% | 4.22% | -3.53 | 1.28% | 19.11 | 6.86% |
| 9/19/2012 | 9.80% | 2.94% | 4.22% | -3.53 | 1.28% | 18.84 | 6.86% |
| 9/19/2012 | 10.05% | 2.94% | 4.22% | -3.53 | 1.28% | 18.84 | 7.11% |
| 9/26/2012 | 9.50% | 2.94% | 4.21% | -3.53 | 1.27% | 18.51 | 6.56% |
| 10/12/2012 | 9.60% | 2.93% | 4.19% | -3.53 | 1.26% | 18.04 | 6.67% |
| 10/23/2012 | 9.75% | 2.93% | 4.17% | -3.53 | 1.24% | 17.84 | 6.82% |
| 10/24/2012 | 10.30% | 2.93% | 4.17% | -3.53 | 1.24% | 17.83 | 7.37% |
| 11/9/2012 | 10.30% | 2.92% | 4.14% | -3.53 | 1.22% | 17.75 | 7.38% |
| 11/28/2012 | 10.40% | 2.90% | 4.11% | -3.54 | 1.22% | 17.60 | 7.50% |
| 11/29/2012 | 9.75% | 2.89% | 4.11% | -3.54 | 1.22% | 17.58 | 6.86% |
| 11/29/2012 | 9.88% | 2.89% | 4.11% | -3.54 | 1.22% | 17.58 | 6.99% |
| 12/5/2012 | 9.71% | 2.89% | 4.10% | -3.54 | 1.21% | 17.53 | 6.82% |
| 12/5/2012 | 10.40% | 2.89% | 4.10% | -3.54 | 1.21% | 17.53 | 7.51% |
| 12/12/2012 | 9.80% | 2.88% | 4.09% | -3.55 | 1.21% | 17.48 | 6.92% |
| 12/13/2012 | 9.50% | 2.88% | 4.09% | -3.55 | 1.21% | 17.47 | 6.62% |
| 12/13/2012 | 10.50% | 2.88% | 4.09% | -3.55 | 1.21% | 17.47 | 7.62% |
| 12/14/2012 | 10.40% | 2.88% | 4.09% | -3.55 | 1.21% | 17.47 | 7.52% |
| 12/19/2012 | 9.71% | 2.87% | 4.09% | -3.55 | 1.22% | 17.44 | 6.84% |
| 12/19/2012 | 10.25% | 2.87% | 4.09% | -3.55 | 1.22% | 17.44 | 7.38% |
| 12/20/2012 | 9.50% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 6.63% |
| 12/20/2012 | 9.80% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 6.93% |
| 12/20/2012 | 10.25% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.38% |
| 12/20/2012 | 10.25% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.38% |
| 12/20/2012 | 10.30% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.43% |
| 12/20/2012 | 10.40% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.53% |
| 12/20/2012 | 10.45% | 2.87% | 4.09% | -3.55 | 1.22% | 17.43 | 7.58% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 12/21/2012 | 10.20% | 2.87% | 4.08% | -3.55 | 1.22% | 17.43 | 7.33% |
| 12/26/2012 | 9.80% | 2.86% | 4.08% | -3.55 | 1.22% | 17.45 | 6.94% |
| 1/9/2013 | 9.70% | 2.84% | 4.06% | -3.56 | 1.22% | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 4.06% | -3.56 | 1.22% | 17.50 | 6.86% |
| 1/9/2013 | 9.70% | 2.84% | 4.06% | -3.56 | 1.22% | 17.50 | 6.86% |
| 1/16/2013 | 9.60% | 2.84% | 4.05% | -3.56 | 1.21% | 17.45 | 6.76% |
| 1/16/2013 | 9.60% | 2.84% | 4.05% | -3.56 | 1.21% | 17.45 | 6.76% |
| 2/13/2013 | 10.20% | 2.84% | 4.03% | -3.56 | 1.18% | 17.01 | 7.36% |
| 2/22/2013 | 9.75% | 2.85% | 4.02% | -3.56 | 1.17% | 16.89 | 6.90% |
| 2/27/2013 | 10.00% | 2.86% | 4.02% | -3.56 | 1.16% | 16.85 | 7.14% |
| 3/14/2013 | 9.30% | 2.88% | 4.02% | -3.55 | 1.14% | 16.34 | 6.42% |
| 3/27/2013 | 9.80% | 2.90% | 4.03% | -3.54 | 1.13% | 15.87 | 6.90% |
| 5/1/2013 | 9.84% | 2.94% | 4.02% | -3.53 | 1.08% | 15.25 | 6.90% |
| 5/15/2013 | 10.30% | 2.96% | 4.03% | -3.52 | 1.07% | 15.02 | 7.34% |
| 5/30/2013 | 10.20% | 2.98% | 4.05% | -3.51 | 1.07% | 14.87 | 7.22% |
| 5/31/2013 | 9.00% | 2.98% | 4.05% | -3.51 | 1.07% | 14.89 | 6.02% |
| 6/11/2013 | 10.00% | 3.00% | 4.06% | -3.51 | 1.06% | 14.95 | 7.00% |
| 6/21/2013 | 9.75% | 3.02% | 4.08% | -3.50 | 1.06% | 14.99 | 6.73% |
| 6/25/2013 | 9.80% | 3.03% | 4.09% | -3.50 | 1.06% | 15.02 | 6.77% |
| 7/12/2013 | 9.36% | 3.08% | 4.13% | -3.48 | 1.06% | 15.06 | 6.28% |
| 8/8/2013 | 9.83% | 3.14% | 4.20% | -3.46 | 1.05% | 14.82 | 6.69% |
| 8/14/2013 | 9.15% | 3.16% | 4.22% | -3.45 | 1.05% | 14.72 | 5.99% |
| 9/11/2013 | 10.20% | 3.27% | 4.31% | -3.42 | 1.04% | 14.56 | 6.93% |
| 9/11/2013 | 10.25% | 3.27% | 4.31% | -3.42 | 1.04% | 14.56 | 6.98% |
| 9/24/2013 | 10.20% | 3.31% | 4.35% | -3.41 | 1.04% | 14.46 | 6.89% |
| 10/3/2013 | 9.65% | 3.33% | 4.38% | -3.40 | 1.04% | 14.45 | 6.32% |
| 11/6/2013 | 10.20% | 3.41% | 4.44% | -3.38 | 1.04% | 14.40 | 6.79% |
| 11/21/2013 | 10.00% | 3.44% | 4.47% | -3.37 | 1.03% | 14.36 | 6.56% |
| 11/26/2013 | 10.00% | 3.45% | 4.48% | -3.37 | 1.03% | 14.36 | 6.55% |
| 12/3/2013 | 10.25% | 3.47% | 4.49% | -3.36 | 1.02% | 14.38 | 6.78% |
| 12/4/2013 | 9.50% | 3.47% | 4.50% | -3.36 | 1.02% | 14.38 | 6.03% |
| 12/5/2013 | 10.20% | 3.48% | 4.50% | -3.36 | 1.02% | 14.38 | 6.72% |
| 12/9/2013 | 8.72% | 3.49% | 4.51% | -3.36 | 1.02% | 14.34 | 5.23% |
| 12/9/2013 | 9.75% | 3.49% | 4.51% | -3.36 | 1.02% | 14.34 | 6.26% |
| 12/13/2013 | 9.75% | 3.50% | 4.52% | -3.35 | 1.02% | 14.34 | 6.25% |
| 12/16/2013 | 9.95% | 3.50% | 4.52% | -3.35 | 1.02% | 14.35 | 6.45% |
| 12/16/2013 | 9.95% | 3.50% | 4.52% | -3.35 | 1.02% | 14.35 | 6.45% |
| 12/16/2013 | 10.12% | 3.50% | 4.52% | -3.35 | 1.02% | 14.35 | 6.62% |
| 12/17/2013 | 9.50% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 5.99% |
| 12/17/2013 | 10.95% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 7.44% |
| 12/18/2013 | 8.72% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 5.21% |
| 12/18/2013 | 9.80% | 3.51% | 4.53% | -3.35 | 1.02% | 14.37 | 6.29% |
| 12/19/2013 | 10.15% | 3.51% | 4.53% | -3.35 | 1.02% | 14.38 | 6.64% |
| 12/30/2013 | 9.50% | 3.54% | 4.55% | -3.34 | 1.01% | 14.41 | 5.96% |
| 2/20/2014 | 9.20% | 3.69% | 4.65% | -3.30 | 0.96% | 14.62 | 5.51% |
| 2/26/2014 | 9.75% | 3.70% | 4.66% | -3.30 | 0.96% | 14.65 | 6.05% |
| 3/17/2014 | 9.55% | 3.72% | 4.68% | -3.29 | 0.96% | 14.72 | 5.83% |
| 3/26/2014 | 9.40% | 3.73% | 4.68% | -3.29 | 0.95% | 14.66 | 5.67% |
| 3/26/2014 | 9.96% | 3.73% | 4.68% | -3.29 | 0.95% | 14.66 | 6.23% |
| 4/2/2014 | 9.70% | 3.73% | 4.68% | -3.29 | 0.95% | 14.58 | 5.97% |
| 5/16/2014 | 9.80% | 3.70% | 4.63% | -3.30 | 0.93% | 14.38 | 6.10% |
| 5/30/2014 | 9.70% | 3.68% | 4.61% | -3.30 | 0.93% | 14.35 | 6.02% |
| 6/6/2014 | 10.40% | 3.67% | 4.60% | -3.30 | 0.93% | 14.26 | 6.73% |
| 6/30/2014 | 9.55% | 3.64% | 4.56% | -3.31 | 0.92% | 13.95 | 5.91% |
| 7/2/2014 | 9.62% | 3.64% | 4.55% | -3.31 | 0.92% | 13.91 | 5.98% |
| 7/10/2014 | 9.95% | 3.63% | 4.54% | -3.32 | 0.91% | 13.86 | 6.32% |
| 7/23/2014 | 9.75% | 3.61% | 4.52% | -3.32 | 0.91% | 13.68 | 6.14% |
| 7/29/2014 | 9.45% | 3.60% | 4.50% | -3.32 | 0.90% | 13.57 | 5.85% |
| 7/31/2014 | 9.90% | 3.60% | 4.50% | -3.32 | 0.90% | 13.55 | 6.30% |
| 8/20/2014 | 9.75% | 3.56% | 4.46% | -3.33 | 0.90% | 13.61 | 6.19% |
| 8/25/2014 | 9.60% | 3.56% | 4.45% | -3.34 | 0.90% | 13.59 | 6.04% |
| 8/29/2014 | 9.80% | 3.54% | 4.44% | -3.34 | 0.90% | 13.57 | 6.26% |
| 9/11/2014 | 9.60% | 3.51% | 4.42% | -3.35 | 0.90% | 13.57 | 6.09% |
| 9/15/2014 | 10.25% | 3.51% | 4.41% | -3.35 | 0.91% | 13.57 | 6.74% |
| 10/9/2014 | 9.80% | 3.44% | 4.36% | -3.37 | 0.91% | 13.62 | 6.36% |
| 11/6/2014 | 9.56% | 3.37% | 4.29% | -3.39 | 0.92% | 14.09 | 6.19% |
| 11/6/2014 | 10.20% | 3.37% | 4.29% | -3.39 | 0.92% | 14.09 | 6.83% |
| 11/14/2014 | 10.20% | 3.35% | 4.28% | -3.40 | 0.93% | 13.94 | 6.85% |
| 11/26/2014 | 9.70% | 3.32% | 4.26% | -3.40 | 0.94% | 13.82 | 6.38% |
| 11/26/2014 | 10.20% | 3.32% | 4.26% | -3.40 | 0.94% | 13.82 | 6.88% |
| 12/4/2014 | 9.68% | 3.30% | 4.25% | -3.41 | 0.95% | 13.78 | 6.38% |
| 12/10/2014 | 9.25% | 3.29% | 4.24% | -3.41 | 0.95% | 13.80 | 5.96% |
| 12/10/2014 | 9.25% | 3.29% | 4.24% | -3.41 | 0.95% | 13.80 | 5.96% |
| 12/11/2014 | 10.07% | 3.28% | 4.24% | -3.42 | 0.95% | 13.83 | 6.79% |
| 12/12/2014 | 10.20% | 3.28% | 4.23% | -3.42 | 0.95% | 13.86 | 6.92% |
| 12/17/2014 | 9.17% | 3.27% | 4.22% | -3.42 | 0.96% | 13.96 | 5.90% |
| 12/18/2014 | 9.83% | 3.26% | 4.22% | -3.42 | 0.96% | 13.98 | 6.57% |
| 1/23/2015 | 9.50% | 3.14% | 4.13% | -3.46 | 0.99% | 14.37 | 6.36% |
| 2/24/2015 | 9.83% | 3.04% | 4.05% | -3.49 | 1.02% | 14.67 | 6.79% |
| 3/18/2015 | 9.75% | 2.98% | 4.02% | -3.51 | 1.04% | 14.90 | 6.77% |
| 3/25/2015 | 9.50% | 2.95% | 4.00% | -3.52 | 1.04% | 14.96 | 6.55% |
| 3/26/2015 | 9.72% | 2.95% | 4.00% | -3.52 | 1.05% | 14.98 | 6.77% |

| [5] Date of Electric Rate Case | [6] Return on Equity (%) | [7] 30 Year Treasury (%) | [8] Moody's Utility A Yield | [9] LN(30-Year Treasury) | [10] Moody's Utility A Credit Spread | [11] VIX | [12] Risk Premium |
|---|---|---|---|---|---|---|---|
| 4/23/2015 | 10.20% | 2.87% | 3.94% | -3.55 | 1.07% | 15.21 | 7.33% |
| 4/29/2015 | 9.53% | 2.86% | 3.93% | -3.56 | 1.07% | 15.22 | 6.67% |
| 5/1/2015 | 9.60% | 2.85% | 3.93% | -3.56 | 1.08% | 15.23 | 6.75% |
| 5/26/2015 | 9.75% | 2.83% | 3.93% | -3.57 | 1.10% | 15.16 | 6.92% |
| 6/17/2015 | 9.00% | 2.82% | 3.94% | -3.57 | 1.13% | 15.30 | 6.18% |
| 6/17/2015 | 9.00% | 2.82% | 3.94% | -3.57 | 1.13% | 15.30 | 6.18% |
| 9/2/2015 | 9.50% | 2.79% | 4.00% | -3.58 | 1.21% | 15.68 | 6.71% |
| 9/10/2015 | 9.30% | 2.79% | 4.01% | -3.58 | 1.22% | 15.99 | 6.51% |
| 10/15/2015 | 9.00% | 2.81% | 4.06% | -3.57 | 1.24% | 16.66 | 6.19% |
| 11/19/2015 | 10.00% | 2.88% | 4.15% | -3.55 | 1.27% | 16.28 | 7.12% |
| 11/19/2015 | 10.30% | 2.88% | 4.15% | -3.55 | 1.27% | 16.28 | 7.42% |
| 12/3/2015 | 10.00% | 2.90% | 4.18% | -3.54 | 1.28% | 16.28 | 7.10% |
| 12/9/2015 | 9.14% | 2.90% | 4.19% | -3.54 | 1.29% | 16.33 | 6.24% |
| 12/9/2015 | 9.14% | 2.90% | 4.19% | -3.54 | 1.29% | 16.33 | 6.24% |
| 12/11/2015 | 10.30% | 2.90% | 4.20% | -3.54 | 1.30% | 16.42 | 7.40% |
| 12/15/2015 | 9.60% | 2.91% | 4.21% | -3.54 | 1.30% | 16.50 | 6.69% |
| 12/17/2015 | 9.70% | 2.91% | 4.21% | -3.54 | 1.30% | 16.54 | 6.79% |
| 12/18/2015 | 9.50% | 2.91% | 4.21% | -3.54 | 1.30% | 16.57 | 6.59% |
| 12/30/2015 | 9.50% | 2.93% | 4.23% | -3.53 | 1.31% | 16.60 | 6.57% |
| 1/6/2016 | 9.50% | 2.94% | 4.25% | -3.53 | 1.31% | 16.72 | 6.56% |
| 2/23/2016 | 9.75% | 2.94% | 4.31% | -3.53 | 1.38% | 18.32 | 6.81% |
| 3/16/2016 | 9.85% | 2.91% | 4.31% | -3.54 | 1.40% | 18.69 | 6.94% |
| 4/29/2016 | 9.80% | 2.83% | 4.25% | -3.56 | 1.42% | 18.60 | 6.97% |
| 6/3/2016 | 9.75% | 2.80% | 4.21% | -3.57 | 1.40% | 18.79 | 6.95% |
| 6/8/2016 | 9.48% | 2.80% | 4.20% | -3.58 | 1.40% | 18.56 | 6.68% |
| 6/15/2016 | 9.00% | 2.78% | 4.19% | -3.58 | 1.40% | 18.29 | 6.22% |
| 6/15/2016 | 9.00% | 2.78% | 4.19% | -3.58 | 1.40% | 18.29 | 6.22% |
| 7/18/2016 | 9.98% | 2.71% | 4.11% | -3.61 | 1.40% | 17.45 | 7.27% |
| 8/9/2016 | 9.85% | 2.66% | 4.05% | -3.63 | 1.39% | 17.07 | 7.19% |
| 8/18/2016 | 9.50% | 2.63% | 4.03% | -3.64 | 1.40% | 16.97 | 6.87% |
| 8/24/2016 | 9.75% | 2.61% | 4.01% | -3.64 | 1.39% | 16.91 | 7.14% |
| 9/1/2016 | 9.50% | 2.59% | 3.98% | -3.65 | 1.39% | 16.78 | 6.91% |
| 9/8/2016 | 10.00% | 2.57% | 3.97% | -3.66 | 1.39% | 16.69 | 7.43% |
| 9/28/2016 | 9.58% | 2.53% | 3.92% | -3.68 | 1.39% | 16.51 | 7.05% |
| 9/30/2016 | 9.90% | 2.53% | 3.91% | -3.68 | 1.38% | 16.46 | 7.37% |
| 11/9/2016 | 9.80% | 2.48% | 3.84% | -3.70 | 1.36% | 15.63 | 7.32% |
| 11/10/2016 | 9.50% | 2.48% | 3.84% | -3.70 | 1.36% | 15.60 | 7.02% |
| 11/15/2016 | 9.55% | 2.49% | 3.84% | -3.69 | 1.35% | 15.49 | 7.06% |
| 11/18/2016 | 10.00% | 2.50% | 3.84% | -3.69 | 1.35% | 15.34 | 7.50% |
| 11/29/2016 | 10.55% | 2.51% | 3.85% | -3.69 | 1.34% | 14.95 | 8.04% |
| 12/1/2016 | 10.00% | 2.51% | 3.85% | -3.68 | 1.34% | 14.87 | 7.49% |
| 12/6/2016 | 8.64% | 2.52% | 3.85% | -3.68 | 1.33% | 14.76 | 6.12% |
| 12/6/2016 | 8.64% | 2.52% | 3.85% | -3.68 | 1.33% | 14.76 | 6.12% |
| 12/7/2016 | 10.10% | 2.52% | 3.85% | -3.68 | 1.33% | 14.72 | 7.58% |
| 12/12/2016 | 9.60% | 2.53% | 3.85% | -3.68 | 1.33% | 14.62 | 7.07% |
| 12/14/2016 | 9.10% | 2.53% | 3.86% | -3.68 | 1.32% | 14.58 | 6.57% |
| 12/19/2016 | 9.00% | 2.54% | 3.86% | -3.67 | 1.32% | 14.50 | 6.46% |
| 12/19/2016 | 9.37% | 2.54% | 3.86% | -3.67 | 1.32% | 14.50 | 6.83% |
| 12/22/2016 | 9.60% | 2.55% | 3.86% | -3.67 | 1.31% | 14.40 | 7.05% |
| 12/22/2016 | 9.90% | 2.55% | 3.86% | -3.67 | 1.31% | 14.40 | 7.35% |
| 12/28/2016 | 9.50% | 2.55% | 3.86% | -3.67 | 1.31% | 14.34 | 6.95% |
| 1/18/2017 | 9.45% | 2.58% | 3.86% | -3.66 | 1.27% | 14.20 | 6.87% |
| 1/24/2017 | 9.00% | 2.59% | 3.86% | -3.65 | 1.27% | 14.12 | 6.41% |
| 1/31/2017 | 10.10% | 2.60% | 3.87% | -3.65 | 1.27% | 14.05 | 7.50% |
| 2/15/2017 | 9.60% | 2.62% | 3.88% | -3.64 | 1.25% | 13.89 | 6.98% |
| 2/22/2017 | 9.60% | 2.64% | 3.88% | -3.64 | 1.25% | 13.82 | 6.96% |
| 2/24/2017 | 9.75% | 2.64% | 3.89% | -3.63 | 1.25% | 13.79 | 7.11% |
| 2/28/2017 | 10.10% | 2.64% | 3.89% | -3.63 | 1.25% | 13.77 | 7.46% |
| 3/2/2017 | 9.41% | 2.65% | 3.89% | -3.63 | 1.24% | 13.74 | 6.76% |
| 3/20/2017 | 9.50% | 2.68% | 3.91% | -3.62 | 1.23% | 13.56 | 6.82% |
| 4/4/2017 | 10.25% | 2.72% | 3.93% | -3.61 | 1.22% | 13.28 | 7.53% |
| 4/12/2017 | 9.40% | 2.74% | 3.94% | -3.60 | 1.20% | 13.06 | 6.66% |
| 4/20/2017 | 9.50% | 2.76% | 3.95% | -3.59 | 1.19% | 13.05 | 6.74% |
| 5/3/2017 | 9.50% | 2.79% | 3.98% | -3.58 | 1.19% | 12.95 | 6.71% |
| 5/11/2017 | 9.20% | 2.81% | 4.00% | -3.57 | 1.18% | 12.88 | 6.39% |
| 5/18/2017 | 9.50% | 2.83% | 4.01% | -3.56 | 1.18% | 12.88 | 6.67% |
| 5/23/2017 | 9.70% | 2.84% | 4.02% | -3.56 | 1.18% | 12.87 | 6.86% |
| 6/16/2017 | 9.65% | 2.89% | 4.05% | -3.54 | 1.16% | 12.69 | 6.76% |
| 6/22/2017 | 9.70% | 2.90% | 4.06% | -3.54 | 1.16% | 12.66 | 6.80% |
| 6/22/2017 | 9.70% | 2.90% | 4.06% | -3.54 | 1.16% | 12.66 | 6.80% |
| 7/24/2017 | 9.50% | 2.95% | 4.09% | -3.52 | 1.14% | 12.24 | 6.55% |
| 8/15/2017 | 10.00% | 2.97% | 4.10% | -3.52 | 1.13% | 11.95 | 7.03% |
| 9/22/2017 | 9.60% | 2.93% | 4.07% | -3.53 | 1.14% | 11.47 | 6.67% |
| 9/28/2017 | 9.80% | 2.92% | 4.06% | -3.53 | 1.14% | 11.42 | 6.88% |
| 10/20/2017 | 9.50% | 2.91% | 4.04% | -3.54 | 1.13% | 11.23 | 6.59% |
| 10/26/2017 | 10.20% | 2.91% | 4.03% | -3.54 | 1.13% | 11.22 | 7.29% |
| 10/26/2017 | 10.25% | 2.91% | 4.03% | -3.54 | 1.13% | 11.22 | 7.34% |
| 10/26/2017 | 10.30% | 2.91% | 4.03% | -3.54 | 1.13% | 11.22 | 7.39% |
| 11/6/2017 | 10.25% | 2.90% | 4.03% | -3.54 | 1.12% | 11.15 | 7.35% |
| 11/15/2017 | 11.95% | 2.89% | 4.01% | -3.54 | 1.12% | 11.14 | 9.06% |
| 11/30/2017 | 10.00% | 2.88% | 4.00% | -3.55 | 1.12% | 11.11 | 7.12% |
| 11/30/2017 | 10.00% | 2.88% | 4.00% | -3.55 | 1.12% | 11.11 | 7.12% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 12/5/2017 | 9.50% | 2.88% | 3.99% | -3.55 | 1.11% | 11.10 | 6.62% |
| 12/6/2017 | 8.40% | 2.87% | 3.99% | -3.55 | 1.11% | 11.10 | 5.53% |
| 12/6/2017 | 8.40% | 2.87% | 3.99% | -3.55 | 1.11% | 11.10 | 5.53% |
| 12/7/2017 | 9.80% | 2.87% | 3.99% | -3.55 | 1.11% | 11.09 | 6.93% |
| 12/14/2017 | 9.60% | 2.86% | 3.98% | -3.55 | 1.11% | 11.04 | 6.74% |
| 12/14/2017 | 9.65% | 2.86% | 3.98% | -3.55 | 1.11% | 11.04 | 6.79% |
| 12/18/2017 | 9.50% | 2.86% | 3.97% | -3.56 | 1.11% | 11.02 | 6.64% |
| 12/20/2017 | 9.58% | 2.85% | 3.97% | -3.56 | 1.11% | 11.00 | 6.73% |
| 12/21/2017 | 9.10% | 2.85% | 3.97% | -3.56 | 1.11% | 10.99 | 6.25% |
| 12/28/2017 | 9.50% | 2.85% | 3.96% | -3.56 | 1.11% | 10.96 | 6.65% |
| 12/29/2017 | 9.51% | 2.85% | 3.95% | -3.56 | 1.11% | 10.96 | 6.66% |
| 1/18/2018 | 9.70% | 2.84% | 3.93% | -3.56 | 1.09% | 10.84 | 6.86% |
| 1/31/2018 | 9.30% | 2.84% | 3.92% | -3.56 | 1.08% | 10.75 | 6.46% |
| 2/2/2018 | 9.98% | 2.84% | 3.92% | -3.56 | 1.08% | 10.76 | 7.14% |
| 2/23/2018 | 9.90% | 2.85% | 3.92% | -3.56 | 1.07% | 11.72 | 7.05% |
| 3/12/2018 | 9.25% | 2.86% | 3.92% | -3.55 | 1.05% | 12.08 | 6.39% |
| 3/15/2018 | 9.00% | 2.87% | 3.92% | -3.55 | 1.05% | 12.18 | 6.13% |
| 3/29/2018 | 10.00% | 2.88% | 3.92% | -3.55 | 1.04% | 12.69 | 7.12% |
| 4/12/2018 | 9.90% | 2.89% | 3.93% | -3.54 | 1.04% | 13.15 | 7.01% |
| 4/13/2018 | 9.73% | 2.89% | 3.94% | -3.54 | 1.04% | 13.18 | 6.84% |
| 4/18/2018 | 9.25% | 2.89% | 3.94% | -3.54 | 1.04% | 13.25 | 6.36% |
| 4/18/2018 | 10.00% | 2.89% | 3.94% | -3.54 | 1.04% | 13.25 | 7.11% |
| 4/26/2018 | 9.50% | 2.90% | 3.95% | -3.54 | 1.04% | 13.42 | 6.60% |
| 5/30/2018 | 9.95% | 2.94% | 3.98% | -3.53 | 1.04% | 13.84 | 7.01% |
| 5/31/2018 | 9.50% | 2.94% | 3.98% | -3.53 | 1.04% | 13.86 | 6.56% |
| 6/14/2018 | 8.80% | 2.96% | 4.01% | -3.52 | 1.05% | 13.86 | 5.84% |
| 6/22/2018 | 9.50% | 2.97% | 4.02% | -3.52 | 1.05% | 13.91 | 6.53% |
| 6/22/2018 | 9.90% | 2.97% | 4.02% | -3.52 | 1.05% | 13.91 | 6.93% |
| 6/28/2018 | 9.35% | 2.97% | 4.03% | -3.52 | 1.06% | 14.03 | 6.38% |
| 6/29/2018 | 9.50% | 2.97% | 4.03% | -3.52 | 1.06% | 14.06 | 6.53% |
| 8/8/2018 | 9.53% | 2.99% | 4.08% | -3.51 | 1.09% | 14.46 | 6.54% |
| 8/21/2018 | 9.70% | 3.00% | 4.10% | -3.51 | 1.09% | 14.58 | 6.70% |
| 8/24/2018 | 9.28% | 3.01% | 4.10% | -3.50 | 1.10% | 14.62 | 6.27% |
| 9/5/2018 | 9.56% | 3.02% | 4.12% | -3.50 | 1.10% | 14.67 | 6.54% |
| 9/14/2018 | 10.00% | 3.03% | 4.14% | -3.50 | 1.11% | 14.79 | 6.97% |
| 9/20/2018 | 9.80% | 3.04% | 4.15% | -3.49 | 1.11% | 14.81 | 6.76% |
| 9/26/2018 | 9.77% | 3.05% | 4.16% | -3.49 | 1.11% | 14.86 | 6.72% |
| 9/26/2018 | 10.00% | 3.05% | 4.16% | -3.49 | 1.11% | 14.86 | 6.95% |
| 9/27/2018 | 9.30% | 3.05% | 4.16% | -3.49 | 1.11% | 14.87 | 6.25% |
| 10/4/2018 | 9.85% | 3.06% | 4.18% | -3.49 | 1.12% | 14.93 | 6.79% |
| 10/29/2018 | 9.60% | 3.10% | 4.23% | -3.47 | 1.13% | 15.84 | 6.50% |
| 10/31/2018 | 9.99% | 3.11% | 4.24% | -3.47 | 1.13% | 15.94 | 6.88% |
| 11/1/2018 | 8.69% | 3.11% | 4.24% | -3.47 | 1.13% | 15.98 | 5.58% |
| 12/4/2018 | 8.69% | 3.14% | 4.29% | -3.46 | 1.16% | 15.93 | 5.55% |
| 12/13/2018 | 9.30% | 3.14% | 4.30% | -3.46 | 1.16% | 16.03 | 6.16% |
| 12/14/2018 | 9.50% | 3.14% | 4.30% | -3.46 | 1.17% | 16.04 | 6.36% |
| 12/19/2018 | 9.84% | 3.14% | 4.31% | -3.46 | 1.17% | 16.14 | 6.70% |
| 12/20/2018 | 9.65% | 3.14% | 4.31% | -3.46 | 1.17% | 16.20 | 6.51% |
| 12/21/2018 | 9.30% | 3.14% | 4.31% | -3.46 | 1.17% | 16.28 | 6.16% |
| 1/9/2019 | 10.00% | 3.14% | 4.32% | -3.46 | 1.18% | 16.66 | 6.86% |
| 2/27/2019 | 9.75% | 3.12% | 4.34% | -3.47 | 1.22% | 16.53 | 6.63% |
| 3/13/2019 | 9.60% | 3.12% | 4.33% | -3.47 | 1.21% | 16.60 | 6.48% |
| 3/14/2019 | 9.00% | 3.12% | 4.33% | -3.47 | 1.21% | 16.59 | 5.88% |
| 3/14/2019 | 9.40% | 3.12% | 4.33% | -3.47 | 1.21% | 16.59 | 6.28% |
| 3/22/2019 | 9.65% | 3.12% | 4.33% | -3.47 | 1.22% | 16.60 | 6.53% |
| 4/30/2019 | 9.73% | 3.11% | 4.31% | -3.47 | 1.20% | 16.53 | 6.62% |
| 4/30/2019 | 9.73% | 3.11% | 4.31% | -3.47 | 1.20% | 16.53 | 6.62% |
| 5/1/2019 | 9.50% | 3.11% | 4.30% | -3.47 | 1.20% | 16.54 | 6.39% |
| 5/2/2019 | 10.00% | 3.11% | 4.30% | -3.47 | 1.20% | 16.55 | 6.89% |
| 5/8/2019 | 9.50% | 3.10% | 4.30% | -3.47 | 1.20% | 16.63 | 6.40% |
| 5/14/2019 | 8.75% | 3.10% | 4.29% | -3.48 | 1.20% | 16.75 | 5.65% |
| 5/16/2019 | 9.50% | 3.09% | 4.29% | -3.48 | 1.20% | 16.78 | 6.41% |
| 5/23/2019 | 9.90% | 3.09% | 4.28% | -3.48 | 1.19% | 16.88 | 6.81% |
| 8/12/2019 | 9.60% | 2.89% | 4.11% | -3.54 | 1.22% | 17.13 | 6.71% |
| 8/29/2019 | 9.06% | 2.81% | 4.03% | -3.57 | 1.22% | 17.01 | 6.25% |
| 9/4/2019 | 10.00% | 2.78% | 4.01% | -3.58 | 1.23% | 16.98 | 7.22% |
| 9/30/2019 | 9.60% | 2.70% | 3.91% | -3.61 | 1.21% | 16.53 | 6.90% |
| 10/31/2019 | 10.00% | 2.60% | 3.80% | -3.65 | 1.21% | 15.55 | 7.40% |
| 10/31/2019 | 10.00% | 2.60% | 3.80% | -3.65 | 1.21% | 15.55 | 7.40% |
| 11/1/2019 | 9.35% | 2.59% | 3.80% | -3.65 | 1.20% | 15.52 | 6.76% |
| 11/29/2019 | 9.50% | 2.52% | 3.72% | -3.68 | 1.20% | 15.10 | 6.98% |
| 12/4/2019 | 8.91% | 2.51% | 3.71% | -3.69 | 1.20% | 15.11 | 6.40% |
| 12/4/2019 | 9.75% | 2.51% | 3.71% | -3.69 | 1.20% | 15.11 | 7.24% |
| 12/16/2019 | 8.91% | 2.48% | 3.67% | -3.70 | 1.19% | 15.10 | 6.43% |
| 12/17/2019 | 9.70% | 2.47% | 3.67% | -3.70 | 1.19% | 15.08 | 7.23% |
| 12/17/2019 | 10.50% | 2.47% | 3.67% | -3.70 | 1.19% | 15.08 | 8.03% |
| 12/19/2019 | 10.20% | 2.47% | 3.66% | -3.70 | 1.19% | 15.04 | 7.73% |
| 12/19/2019 | 10.25% | 2.47% | 3.66% | -3.70 | 1.19% | 15.04 | 7.78% |
| 12/19/2019 | 10.30% | 2.47% | 3.66% | -3.70 | 1.19% | 15.04 | 7.83% |
| 12/20/2019 | 9.45% | 2.46% | 3.65% | -3.70 | 1.19% | 15.03 | 6.99% |
| 12/20/2019 | 9.65% | 2.46% | 3.65% | -3.70 | 1.19% | 15.03 | 7.19% |
| 12/24/2019 | 9.50% | 2.46% | 3.65% | -3.71 | 1.19% | 15.02 | 7.04% |

| [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
|---|---|---|---|---|---|---|---|
| Date of Electric Rate Case | Return on Equity (%) | 30 Year Treasury (%) | Moody's Utility A Yield | LN(30-Year Treasury) | Moody's Utility A Credit Spread | VIX | Risk Premium |
| 1/8/2020 | 10.02% | 2.43% | 3.61% | -3.72 | 1.19% | 14.99 | 7.59% |
| 1/16/2020 | 8.80% | 2.41% | 3.59% | -3.73 | 1.18% | 14.95 | 6.39% |
| 1/22/2020 | 9.50% | 2.39% | 3.58% | -3.73 | 1.19% | 14.94 | 7.11% |
| 1/23/2020 | 9.86% | 2.39% | 3.58% | -3.73 | 1.19% | 14.93 | 7.47% |
| 2/6/2020 | 10.00% | 2.34% | 3.53% | -3.75 | 1.18% | 15.13 | 7.66% |
| 2/11/2020 | 9.30% | 2.33% | 3.51% | -3.76 | 1.18% | 15.16 | 6.97% |
| 2/14/2020 | 9.40% | 2.32% | 3.50% | -3.76 | 1.18% | 15.16 | 7.08% |
| 2/19/2020 | 8.25% | 2.31% | 3.49% | -3.77 | 1.18% | 15.16 | 5.94% |
| 2/24/2020 | 9.75% | 2.29% | 3.48% | -3.78 | 1.18% | 15.16 | 7.46% |
| 2/27/2020 | 9.40% | 2.28% | 3.46% | -3.78 | 1.18% | 15.36 | 7.12% |
| 3/11/2020 | 9.70% | 2.23% | 3.41% | -3.81 | 1.19% | 16.54 | 7.47% |
| 3/25/2020 | 9.40% | 2.17% | 3.41% | -3.83 | 1.24% | 19.18 | 7.23% |
| 4/17/2020 | 9.70% | 2.07% | 3.39% | -3.88 | 1.32% | 21.82 | 7.63% |
| | | | | | | Average: | 6.05% |
| | | | | | | # of Rate Cases: | 751 |

Mr. O'Donnell's Proxy Group Capital Structure - Consolidated

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 57.26% | 58.49% | 58.29% | 59.20% | 58.22% | 58.12% | 58.26% | 57.91% | 58.22% |
| Alliant Energy Corporation | LNT | 44.45% | 43.24% | 45.34% | 45.45% | 44.27% | 44.24% | 46.28% | 46.19% | 44.93% |
| Ameren Corporation | AEE | 47.18% | 47.55% | 47.28% | 47.49% | 48.09% | 46.61% | 47.67% | 47.52% | 47.42% |
| American Electric Power Co. | AEP | 42.00% | 41.85% | 42.65% | 44.60% | 45.50% | 45.94% | 46.27% | 46.00% | 44.35% |
| CMS Energy Corporation | CMS | 27.24% | 28.04% | 28.66% | 28.93% | 30.32% | 30.65% | 30.71% | 30.09% | 29.33% |
| Consolidated Edison, Inc. | ED | 46.91% | 46.54% | 46.68% | 47.97% | 48.89% | 47.87% | 49.42% | 49.03% | 47.91% |
| Dominion Energy, Inc. | D | 41.58% | 39.80% | 39.97% | 36.59% | 34.36% | 34.00% | 33.75% | 33.50% | 36.69% |
| Duke Energy Corporation | DUK | 42.74% | 42.95% | 43.23% | 44.55% | 44.34% | 44.64% | 44.10% | 44.39% | 43.87% |
| Edison International | EIX | 41.88% | 38.51% | 38.65% | 41.55% | 45.13% | 45.13% | 45.79% | 49.05% | 43.21% |
| Entergy Corporation | ETR | 36.10% | 35.69% | 33.75% | 35.33% | 33.72% | 33.54% | 32.09% | 34.61% | 34.35% |
| Eversource Energy | ES | 44.79% | 45.21% | 45.82% | 45.55% | 46.41% | 46.38% | 46.03% | 47.33% | 45.94% |
| Hawaiian Electric Industries | HE | 51.16% | 50.63% | 50.09% | 52.91% | 53.77% | 53.40% | 54.66% | 54.75% | 52.67% |
| IDACORP, Inc. | IDA | 57.30% | 56.70% | 56.47% | 56.37% | 56.35% | 55.56% | 53.48% | 56.32% | 56.07% |
| MGE Energy, Inc. | MGEE | 62.36% | 61.80% | 61.65% | 62.04% | 61.94% | 65.38% | 65.12% | 64.81% | 63.14% |
| NextEra Energy, Inc. | NEE | 48.39% | 48.80% | 51.30% | 53.48% | 53.56% | 52.42% | 52.81% | 45.88% | 50.83% |
| NorthWestern Corporation | NWE | 47.67% | 47.94% | 48.59% | 47.76% | 48.24% | 48.28% | 47.34% | 49.74% | 48.19% |
| OGE Energy Corp. | OGE | 56.36% | 55.28% | 57.44% | 56.00% | 56.15% | 56.46% | 56.16% | 56.22% | 56.26% |
| Otter Tail Corporation | OTTR | 55.26% | 54.95% | 54.78% | 55.26% | 55.14% | 54.77% | 54.54% | 58.69% | 55.42% |
| Pinnacle West Capital Corp. | PNW | 50.18% | 49.92% | 49.98% | 50.41% | 51.27% | 51.22% | 50.74% | 50.68% | 50.55% |
| PNM Resources, Inc. | PNM | 35.82% | 35.57% | 35.23% | 38.74% | 40.39% | 39.91% | 39.47% | 41.02% | 38.27% |
| Portland General Electric Company | POR | 49.82% | 49.72% | 50.27% | 50.28% | 50.60% | 50.40% | 50.24% | 49.90% | 50.15% |
| Public Service Enterprise Group Incorporated | PEG | 48.56% | 48.51% | 50.72% | 49.85% | 50.00% | 50.17% | 51.90% | 51.44% | 50.14% |
| Sempra Energy | SRE | 41.40% | 38.85% | 40.20% | 39.71% | 39.56% | 38.70% | 38.37% | 41.48% | 39.78% |
| Southern Company | SO | 36.80% | 37.54% | 37.15% | 36.01% | 35.89% | 34.58% | 34.10% | 33.32% | 35.67% |
| WEC Energy Group | WEC | 46.35% | 48.28% | 48.18% | 48.59% | 50.74% | 50.58% | 50.24% | 49.67% | 49.08% |
| Xcel Energy Inc. | XEL | 40.20% | 40.11% | 40.79% | 42.99% | 43.09% | 41.88% | 43.56% | 43.34% | 42.00% |
| Mean | | 46.14% | 45.86% | 46.27% | 46.83% | 47.15% | 46.96% | 47.04% | 47.42% | 46.71% |

Mr. O'Donnell's Proxy Group Capital Structure - Consolidated

| | | | | | | % Long-Term Debt | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 42.74% | 41.51% | 41.71% | 40.80% | 41.78% | 41.88% | 41.74% | 42.09% | 41.78% |
| Alliant Energy Corporation | LNT | 55.55% | 56.76% | 54.66% | 54.55% | 55.73% | 55.76% | 53.72% | 53.81% | 55.07% |
| Ameren Corporation | AEE | 52.82% | 52.45% | 52.72% | 52.51% | 51.91% | 53.39% | 52.33% | 52.48% | 52.58% |
| American Electric Power Co. | AEP | 58.00% | 58.15% | 57.35% | 55.40% | 54.50% | 54.06% | 53.73% | 54.00% | 55.65% |
| CMS Energy Corporation | CMS | 72.76% | 71.96% | 71.34% | 71.07% | 69.68% | 69.35% | 69.29% | 69.91% | 70.67% |
| Consolidated Edison, Inc. | ED | 53.09% | 53.46% | 53.32% | 52.03% | 51.11% | 52.13% | 50.58% | 50.97% | 52.09% |
| Dominion Energy, Inc. | D | 58.42% | 60.20% | 60.03% | 63.41% | 65.64% | 66.00% | 66.25% | 66.50% | 63.31% |
| Duke Energy Corporation | DUK | 57.26% | 57.05% | 56.77% | 55.45% | 55.66% | 55.36% | 55.90% | 55.61% | 56.13% |
| Edison International | EIX | 58.12% | 61.49% | 61.35% | 58.45% | 54.87% | 54.87% | 54.21% | 50.95% | 56.79% |
| Entergy Corporation | ETR | 63.90% | 64.31% | 66.25% | 64.67% | 66.28% | 66.46% | 67.91% | 65.39% | 65.65% |
| Eversource Energy | ES | 55.21% | 54.79% | 54.18% | 54.45% | 53.59% | 53.62% | 53.97% | 52.67% | 54.06% |
| Hawaiian Electric Industries | HE | 48.84% | 49.37% | 49.91% | 47.09% | 46.23% | 46.60% | 45.34% | 45.25% | 47.33% |
| IDACORP, Inc. | IDA | 42.70% | 43.30% | 43.53% | 43.63% | 43.65% | 44.44% | 46.52% | 43.68% | 43.93% |
| MGE Energy, Inc. | MGEE | 37.64% | 38.20% | 38.35% | 37.96% | 38.06% | 34.62% | 34.88% | 35.19% | 36.86% |
| NextEra Energy, Inc. | NEE | 51.61% | 51.20% | 48.70% | 46.52% | 46.44% | 47.58% | 47.19% | 54.12% | 49.17% |
| NorthWestern Corporation | NWE | 52.33% | 52.06% | 51.41% | 52.24% | 51.76% | 51.72% | 52.66% | 50.26% | 51.81% |
| OGE Energy Corp. | OGE | 43.64% | 44.72% | 42.56% | 44.00% | 43.85% | 43.54% | 43.84% | 43.78% | 43.74% |
| Otter Tail Corporation | OTTR | 44.74% | 45.05% | 45.22% | 44.74% | 44.86% | 45.23% | 45.46% | 41.31% | 44.58% |
| Pinnacle West Capital Corp. | PNW | 49.82% | 50.08% | 50.02% | 49.59% | 48.73% | 48.78% | 49.26% | 49.32% | 49.45% |
| PNM Resources, Inc. | PNM | 64.18% | 64.43% | 64.77% | 61.26% | 59.61% | 60.09% | 60.53% | 58.98% | 61.73% |
| Portland General Electric Company | POR | 50.18% | 50.28% | 49.73% | 49.72% | 49.40% | 49.60% | 49.76% | 50.10% | 49.85% |
| Public Service Enterprise Group Incorporated | PEG | 51.44% | 51.49% | 49.28% | 50.15% | 50.00% | 49.83% | 48.10% | 48.56% | 49.86% |
| Sempra Energy | SRE | 58.60% | 61.15% | 59.80% | 60.29% | 60.44% | 61.30% | 61.63% | 58.52% | 60.22% |
| Southern Company | SO | 63.20% | 62.46% | 62.85% | 63.99% | 64.11% | 65.42% | 65.90% | 66.68% | 64.33% |
| WEC Energy Group | WEC | 53.65% | 51.72% | 51.82% | 51.41% | 49.26% | 49.42% | 49.76% | 50.33% | 50.92% |
| Xcel Energy Inc. | XEL | 59.80% | 59.89% | 59.21% | 57.01% | 56.91% | 58.12% | 56.44% | 56.66% | 58.00% |
| Mean | | 53.86% | 54.14% | 53.73% | 53.17% | 52.85% | 53.04% | 52.96% | 52.58% | 53.29% |

Mr. O'Donnell's Proxy Group Capital Structure - Operating Company Level

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 58.68% | 59.66% | 59.53% | 59.12% | 58.50% | 58.84% | 63.09% | 62.51% | 59.99% |
| Alliant Energy Corporation | LNT | 51.73% | 50.38% | 53.18% | 53.11% | 51.13% | 51.00% | 49.74% | 49.77% | 51.26% |
| Ameren Corporation | AEE | 53.67% | 53.03% | 52.81% | 52.69% | 53.22% | 52.01% | 53.04% | 52.65% | 52.89% |
| American Electric Power Co. | AEP | 49.91% | 48.80% | 49.62% | 49.40% | 48.68% | 48.52% | 48.60% | 48.91% | 49.06% |
| CMS Energy Corporation | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison, Inc. | ED | 49.85% | 49.08% | 48.75% | 47.97% | 48.38% | 48.73% | 49.75% | 49.23% | 48.97% |
| Dominion Energy, Inc. | D | 53.56% | 50.98% | 50.47% | 48.75% | 51.63% | 51.12% | 50.17% | 50.62% | 50.91% |
| Duke Energy Corporation | DUK | 52.89% | 54.48% | 53.14% | 54.35% | 55.03% | 54.94% | 54.46% | 54.30% | 54.20% |
| Edison International | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Corporation | ETR | 49.10% | 48.19% | 48.81% | 50.11% | 49.96% | 49.95% | 48.60% | 48.97% | 49.21% |
| Eversource Energy | ES | 49.53% | 49.38% | 54.22% | 53.28% | 51.03% | 50.14% | 54.05% | 54.60% | 52.03% |
| Hawaiian Electric Industries | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| IDACORP, Inc. | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| MGE Energy, Inc. | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| NextEra Energy, Inc. | NEE | 56.15% | 61.22% | 61.05% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 61.20% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| OGE Energy Corp. | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Corporation | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Pinnacle West Capital Corp. | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| PNM Resources, Inc. | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Public Service Enterprise Group Incorporated | PEG | 54.65% | 54.31% | 55.14% | 54.24% | 53.69% | 53.93% | 54.20% | 53.41% | 54.20% |
| Sempra Energy | SRE | 56.17% | 56.30% | 53.82% | 53.29% | 53.13% | 54.39% | 54.20% | 53.27% | 54.32% |
| Southern Company | SO | 52.36% | 52.93% | 52.80% | 54.21% | 51.50% | 50.31% | 49.98% | 47.67% | 51.47% |
| WEC Energy Group | WEC | 55.79% | 56.71% | 55.73% | 53.46% | 58.30% | 57.72% | 61.62% | 54.62% | 56.74% |
| Xcel Energy Inc. | XEL | 53.98% | 54.70% | 54.51% | 54.22% | 53.37% | 53.63% | 54.15% | 53.95% | 54.06% |
| Mean | | 53.18% | 53.04% | 53.03% | 52.87% | 53.08% | 52.90% | 53.19% | 53.10% | 53.05% |

Operating Company Capital Structure

| | | % Common Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 59.33% | 60.94% | 60.87% | 61.39% | 60.43% | 60.33% | 60.38% | 60.04% | 60.46% |
| Superior Water, Light and Power Company | ALE | 58.03% | 58.38% | 58.19% | 56.86% | 56.58% | 57.34% | 65.80% | 64.99% | 59.52% |
| Interstate Power and Light Company | LNT | 50.06% | 51.76% | 53.33% | 53.52% | 49.64% | 50.47% | 49.92% | 50.31% | 51.13% |
| Wisconsin Power and Light Company | LNT | 53.40% | 49.01% | 53.03% | 52.69% | 52.62% | 51.52% | 49.57% | 49.23% | 51.38% |
| Ameren Illinois Company | AEE | 54.46% | 54.05% | 53.65% | 52.86% | 53.18% | 52.74% | 54.24% | 53.38% | 53.57% |
| Union Electric Company | AEE | 52.88% | 52.00% | 51.96% | 52.52% | 53.26% | 51.28% | 51.84% | 51.92% | 52.21% |
| AEP Texas Inc. | AEP | 46.97% | 46.32% | 47.54% | 45.38% | 43.80% | 43.20% | 46.75% | 45.14% | 45.64% |
| Appalachian Power Company | AEP | 48.74% | 48.19% | 47.77% | 49.51% | 49.30% | 48.93% | 49.35% | 48.72% | 48.81% |
| Indiana Michigan Power Company | AEP | 46.51% | 45.83% | 45.43% | 44.62% | 44.53% | 44.15% | 46.64% | 46.33% | 45.50% |
| Kentucky Power Company | AEP | 46.94% | 46.50% | 46.42% | 45.72% | 45.28% | 44.89% | 44.40% | 43.52% | 45.46% |
| Kingsport Power Company | AEP | 54.24% | 50.18% | 51.54% | 50.79% | 50.71% | 47.69% | 47.28% | 46.53% | 49.87% |
| Ohio Power Company | AEP | 53.63% | 52.92% | 58.86% | 57.80% | 56.85% | 57.11% | 52.91% | 58.63% | 56.09% |
| Public Service Company of Oklahoma | AEP | 49.89% | 48.02% | 47.19% | 49.16% | 49.55% | 48.59% | 48.10% | 48.50% | 48.62% |
| Southwestern Electric Power Company | AEP | 48.63% | 47.45% | 47.59% | 46.97% | 43.43% | 47.91% | 47.72% | 48.52% | 47.28% |
| Wheeling Power Company | AEP | 53.66% | 53.83% | 54.27% | 54.62% | 54.70% | 54.19% | 54.27% | 54.26% | 54.23% |
| Consumers Energy Company | CMS | 51.70% | 53.64% | 52.52% | 50.27% | 53.01% | 52.86% | 53.13% | 52.25% | 52.42% |
| Consolidated Edison Company of New York, Inc. | ED | 49.29% | 48.92% | 48.30% | 47.52% | 48.33% | 46.72% | 48.66% | 48.22% | 48.24% |
| Orange and Rockland Utilities, Inc. | ED | 50.40% | 49.25% | 49.21% | 48.41% | 48.44% | 50.74% | 50.83% | 50.25% | 49.69% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 53.33% | 53.30% | 52.42% | 52.62% | 53.64% | 52.81% | 51.03% | 51.71% | 52.61% |
| Dominion Energy South Carolina, Inc. | D | 53.80% | 48.67% | 48.52% | 44.88% | 49.63% | 49.44% | 49.30% | 49.54% | 49.22% |
| Duke Energy Carolinas, LLC | DUK | 51.80% | 52.94% | 52.32% | 51.78% | 52.64% | 52.10% | 51.70% | 52.98% | 52.28% |
| Duke Energy Florida, LLC | DUK | 52.82% | 51.55% | 50.56% | 50.04% | 49.65% | 48.79% | 49.92% | 49.25% | 50.32% |
| Duke Energy Indiana, LLC | DUK | 51.52% | 54.83% | 54.29% | 53.26% | 52.79% | 52.64% | 52.54% | 51.94% | 52.98% |
| Duke Energy Kentucky, Inc. | DUK | 45.44% | 53.04% | 52.81% | 51.95% | 56.58% | 55.79% | 53.72% | 53.11% | 52.80% |
| Duke Energy Ohio, Inc. | DUK | 64.90% | 64.45% | 59.29% | 68.09% | 67.73% | 67.10% | 66.06% | 66.24% | 65.48% |
| Duke Energy Progress, LLC | DUK | 50.86% | 50.09% | 49.60% | 51.00% | 50.76% | 53.22% | 52.82% | 52.27% | 51.33% |
| Southern California Edison Company | EIX | 50.14% | 48.40% | 45.15% | 46.90% | 49.82% | 50.05% | 50.63% | 53.08% | 49.27% |
| Entergy Arkansas, LLC | ETR | 47.72% | 46.49% | 47.04% | 49.42% | 49.38% | 48.29% | 45.88% | 45.95% | 47.52% |
| Entergy Louisiana, LLC | ETR | 47.13% | 46.32% | 45.79% | 47.37% | 46.77% | 46.97% | 44.58% | 47.43% | 46.55% |
| Entergy Mississippi, LLC | ETR | 48.35% | 44.93% | 49.41% | 49.11% | 50.10% | 49.10% | 48.32% | 47.85% | 48.40% |
| Entergy New Orleans, LLC | ETR | 53.69% | 52.40% | 51.69% | 51.19% | 50.93% | 54.02% | 53.43% | 53.16% | 52.56% |
| Entergy Texas, Inc. | ETR | 48.63% | 50.79% | 50.13% | 53.46% | 52.61% | 51.38% | 50.79% | 50.45% | 51.03% |
| Connecticut Light and Power Company | ES | 54.12% | 55.38% | 58.18% | 56.18% | 54.49% | 53.85% | 50.40% | 53.82% | 54.55% |
| NSTAR Electric Company | ES | 53.81% | 52.74% | 56.08% | 55.74% | 55.50% | 54.51% | 53.83% | 53.85% | 54.51% |
| Public Service Company of New Hampshire | ES | 40.64% | 40.02% | 48.38% | 47.92% | 43.11% | 42.06% | 57.93% | 57.30% | 47.17% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 53.43% | 53.43% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 58.43% | 58.17% | 58.06% | 57.98% | 56.09% | 55.78% | 57.44% | 57.42% | 57.42% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 55.20% | 54.58% | 54.36% | 54.25% | 54.25% | 53.44% | 51.37% | 54.22% | 53.96% |
| Madison Gas and Electric Company | MGEE | 59.66% | 58.84% | 58.46% | 57.90% | 57.36% | 60.66% | 60.20% | 59.73% | 59.10% |
| Florida Power & Light Company | NEE | 59.78% | 61.30% | 64.03% | 64.37% | 64.78% | 60.84% | 61.23% | 59.93% | 62.03% |
| Gulf Power Company | NEE | 52.52% | 61.15% | 58.06% | NA | NA | NA | NA | NA | 57.24% |
| NorthWestern Corporation | NWE | 47.80% | 48.07% | 48.74% | 47.88% | 48.36% | 48.41% | 47.48% | 49.89% | 48.33% |
| Oklahoma Gas and Electric Company | OGE | 54.96% | 53.47% | 55.38% | 53.20% | 53.05% | 54.25% | 53.59% | 53.36% | 53.91% |
| Otter Tail Power Company | OTTR | 55.43% | 53.75% | 53.90% | 53.58% | 53.49% | 53.11% | 52.67% | 57.34% | 54.16% |
| Arizona Public Service Company | PNW | 54.25% | 54.41% | 54.48% | 54.36% | 53.68% | 53.71% | 53.18% | 53.14% | 53.90% |
| Public Service Company of New Mexico | PNM | 45.33% | 43.86% | 43.45% | 45.63% | 48.01% | 46.68% | 46.20% | 46.06% | 45.65% |
| Portland General Electric Company | POR | 51.78% | 51.56% | 50.60% | 50.19% | 50.51% | 50.29% | 50.14% | 49.80% | 50.61% |
| Public Service Electric and Gas Company | PEG | 54.65% | 54.31% | 55.14% | 54.24% | 53.69% | 53.93% | 54.20% | 53.41% | 54.20% |
| Oncor Electric Delivery Company LLC | SRE | 54.91% | 57.43% | 59.79% | 59.47% | 59.29% | 62.31% | 60.34% | 58.86% | 59.05% |
| San Diego Gas & Electric Company | SRE | 57.43% | 55.17% | 56.60% | 55.79% | 55.17% | 54.47% | 55.92% | 55.09% | 55.71% |
| Sharyland Utilities, LLC | SRE | NA | NA | 45.05% | 44.62% | 44.92% | 46.39% | 46.34% | 45.86% | 45.53% |
| Alabama Power Company | SO | 51.45% | 52.54% | 52.23% | 47.77% | 48.13% | 47.51% | 48.86% | 47.07% | 49.44% |
| Georgia Power Company | SO | 55.38% | 56.39% | 56.43% | 59.02% | 57.27% | 54.97% | 53.81% | 50.06% | 55.42% |
| Mississippi Power Company | SO | 50.23% | 49.87% | 49.73% | 50.35% | 45.28% | 43.87% | 43.00% | 39.34% | 46.46% |
| Gulf Power Company | SO | NA | NA | NA | 59.73% | 55.34% | 54.90% | 54.27% | 54.19% | 55.69% |
| Upper Michigan Energy Resources Corporation | WEC | 56.09% | 54.45% | 52.54% | 47.01% | 55.08% | 54.53% | 70.04% | 49.85% | 54.95% |
| Wisconsin Electric Power Company | WEC | 56.92% | 56.64% | 55.78% | 56.03% | 59.25% | 59.09% | 56.47% | 55.94% | 57.01% |
| Wisconsin Public Service Corporation | WEC | 54.37% | 59.04% | 58.88% | 57.33% | 60.59% | 59.53% | 58.35% | 58.06% | 58.27% |
| Northern States Power Company - MN | XEL | 51.79% | 53.66% | 53.64% | 52.81% | 52.64% | 52.61% | 52.59% | 52.38% | 52.77% |
| Northern States Power Company - WI | XEL | 53.56% | 53.49% | 53.59% | 53.60% | 48.45% | 53.85% | 53.79% | 53.36% | 52.96% |
| Public Service Company of Colorado | XEL | 56.35% | 57.53% | 56.68% | 56.31% | 56.08% | 54.17% | 56.67% | 56.50% | 56.29% |
| Southwestern Public Service Company | XEL | 54.21% | 54.14% | 54.13% | 54.17% | 56.29% | 53.88% | 53.54% | 53.55% | 54.24% |
| Mean | | 52.54% | 52.50% | 52.65% | 52.49% | 52.45% | 52.27% | 52.61% | 52.27% | 52.52% |

Source: S&P Global Market Intelligence

Mr. O'Donnell's Proxy Group Capital Structure - Operating Company Level

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Company | Ticker | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE, Inc. | ALE | 41.32% | 40.34% | 40.47% | 40.88% | 41.50% | 41.16% | 36.91% | 37.49% | 40.01% |
| Alliant Energy Corporation | LNT | 48.27% | 49.62% | 46.82% | 46.89% | 48.87% | 49.00% | 50.26% | 50.23% | 48.74% |
| Ameren Corporation | AEE | 46.33% | 46.97% | 47.19% | 47.31% | 46.78% | 47.99% | 46.96% | 47.35% | 47.11% |
| American Electric Power Co. | AEP | 50.09% | 51.20% | 50.38% | 50.60% | 51.32% | 51.48% | 51.40% | 51.09% | 50.94% |
| CMS Energy Corporation | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison, Inc. | ED | 50.15% | 50.92% | 51.25% | 52.03% | 51.62% | 51.27% | 50.25% | 50.77% | 51.03% |
| Dominion Energy, Inc. | D | 46.44% | 49.02% | 49.53% | 51.25% | 48.37% | 48.88% | 49.83% | 49.38% | 49.09% |
| Duke Energy Corporation | DUK | 47.11% | 45.52% | 46.86% | 45.65% | 44.97% | 45.06% | 45.54% | 45.70% | 45.80% |
| Edison International | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Corporation | ETR | 50.90% | 51.81% | 51.19% | 49.89% | 50.04% | 50.05% | 51.40% | 51.03% | 50.79% |
| Eversource Energy | ES | 50.47% | 50.62% | 45.78% | 46.72% | 48.97% | 49.86% | 45.95% | 45.40% | 47.97% |
| Hawaiian Electric Industries | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| IDACORP, Inc. | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| MGE Energy, Inc. | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| NextEra Energy, Inc. | NEE | 43.85% | 38.78% | 38.95% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 38.80% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| OGE Energy Corp. | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Corporation | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Pinnacle West Capital Corp. | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| PNM Resources, Inc. | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Public Service Enterprise Group Incorporated | PEG | 45.35% | 45.69% | 44.86% | 45.76% | 46.31% | 46.07% | 45.80% | 46.59% | 45.80% |
| Sempra Energy | SRE | 43.83% | 43.70% | 46.18% | 46.71% | 46.87% | 45.61% | 45.80% | 46.73% | 45.68% |
| Southern Company | SO | 47.64% | 47.07% | 47.20% | 45.79% | 48.50% | 49.69% | 50.02% | 52.33% | 48.53% |
| WEC Energy Group | WEC | 44.21% | 43.29% | 44.27% | 46.54% | 41.70% | 42.28% | 38.38% | 45.38% | 43.26% |
| Xcel Energy Inc. | XEL | 46.02% | 45.30% | 45.49% | 45.78% | 46.63% | 46.37% | 45.85% | 46.05% | 45.94% |
| Mean | | 46.82% | 46.96% | 46.97% | 47.13% | 46.92% | 47.10% | 46.81% | 46.90% | 46.95% |

Operating Company Capital Structure

| | | % Long-Term Debt | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Operating Company | Parent | 2019Q3 | 2019Q2 | 2019Q1 | 2018Q4 | 2018Q3 | 2018Q2 | 2018Q1 | 2017Q4 | Average |
| ALLETE (Minnesota Power) | ALE | 40.67% | 39.06% | 39.13% | 38.61% | 39.57% | 39.67% | 39.62% | 39.96% | 39.54% |
| Superior Water, Light and Power Company | ALE | 41.97% | 41.62% | 41.81% | 43.14% | 43.42% | 42.66% | 34.20% | 35.01% | 40.48% |
| Interstate Power and Light Company | LNT | 49.94% | 48.24% | 46.67% | 46.48% | 50.36% | 49.53% | 50.08% | 49.69% | 48.87% |
| Wisconsin Power and Light Company | LNT | 46.60% | 50.99% | 46.97% | 47.31% | 47.38% | 48.48% | 50.43% | 50.77% | 48.62% |
| Ameren Illinois Company | AEE | 45.54% | 45.95% | 46.35% | 47.14% | 46.82% | 47.26% | 45.76% | 46.62% | 46.43% |
| Union Electric Company | AEE | 47.12% | 48.00% | 48.04% | 47.48% | 46.74% | 48.72% | 48.16% | 48.08% | 47.79% |
| AEP Texas Inc. | AEP | 53.03% | 53.68% | 52.46% | 54.62% | 56.20% | 56.80% | 53.25% | 54.86% | 54.36% |
| Appalachian Power Company | AEP | 51.26% | 51.81% | 52.23% | 50.49% | 50.70% | 51.07% | 50.65% | 51.28% | 51.19% |
| Indiana Michigan Power Company | AEP | 53.49% | 54.17% | 54.57% | 55.38% | 55.47% | 55.85% | 53.36% | 53.67% | 54.50% |
| Kentucky Power Company | AEP | 53.06% | 53.50% | 53.58% | 54.28% | 54.72% | 55.11% | 55.60% | 56.48% | 54.54% |
| Kingsport Power Company | AEP | 45.76% | 49.82% | 48.46% | 49.21% | 49.29% | 52.31% | 52.72% | 53.47% | 50.13% |
| Ohio Power Company | AEP | 46.37% | 47.08% | 41.14% | 42.20% | 43.15% | 42.89% | 47.09% | 41.37% | 43.91% |
| Public Service Company of Oklahoma | AEP | 50.11% | 51.98% | 52.81% | 50.84% | 50.45% | 51.41% | 51.90% | 51.50% | 51.38% |
| Southwestern Electric Power Company | AEP | 51.37% | 52.55% | 52.41% | 53.03% | 56.57% | 52.09% | 52.28% | 51.48% | 52.72% |
| Wheeling Power Company | AEP | 46.34% | 46.17% | 45.73% | 45.38% | 45.30% | 45.81% | 45.73% | 45.74% | 45.77% |
| Consumers Energy Company | CMS | 48.30% | 46.36% | 47.48% | 49.73% | 46.99% | 47.14% | 46.87% | 47.75% | 47.58% |
| Consolidated Edison Company of New York, Inc. | ED | 50.71% | 51.08% | 51.70% | 52.48% | 51.67% | 53.28% | 51.34% | 51.78% | 51.76% |
| Orange and Rockland Utilities, Inc. | ED | 49.60% | 50.75% | 50.79% | 51.59% | 51.56% | 49.26% | 49.17% | 49.75% | 50.31% |
| Rockland Electric Company | ED | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Virginia Electric and Power Company | D | 46.67% | 46.70% | 47.58% | 47.38% | 46.36% | 47.19% | 48.97% | 48.29% | 47.39% |
| Dominion Energy South Carolina, Inc. | D | 46.20% | 51.33% | 51.48% | 55.12% | 50.37% | 50.56% | 50.70% | 50.46% | 50.78% |
| Duke Energy Carolinas, LLC | DUK | 48.20% | 47.06% | 47.68% | 48.22% | 47.36% | 47.90% | 48.30% | 47.02% | 47.72% |
| Duke Energy Florida, LLC | DUK | 47.18% | 48.45% | 49.44% | 49.96% | 50.35% | 51.21% | 50.08% | 50.75% | 49.68% |
| Duke Energy Indiana, LLC | DUK | 48.48% | 45.17% | 45.71% | 46.74% | 47.21% | 47.36% | 47.46% | 48.06% | 47.02% |
| Duke Energy Kentucky, Inc. | DUK | 54.56% | 46.96% | 47.19% | 48.05% | 43.42% | 44.21% | 46.28% | 46.89% | 47.20% |
| Duke Energy Ohio, Inc. | DUK | 35.10% | 35.55% | 40.71% | 31.91% | 32.27% | 32.90% | 33.94% | 33.76% | 34.52% |
| Duke Energy Progress, LLC | DUK | 49.14% | 49.91% | 50.40% | 49.00% | 49.24% | 46.78% | 47.18% | 47.73% | 48.67% |
| Southern California Edison Company | EIX | 49.86% | 51.60% | 54.85% | 53.10% | 50.18% | 49.95% | 49.37% | 46.92% | 50.73% |
| Entergy Arkansas, LLC | ETR | 52.28% | 53.51% | 52.96% | 50.58% | 50.62% | 51.71% | 54.12% | 54.05% | 52.48% |
| Entergy Louisiana, LLC | ETR | 52.87% | 53.68% | 54.21% | 52.63% | 53.23% | 53.03% | 55.42% | 52.57% | 53.45% |
| Entergy Mississippi, LLC | ETR | 51.65% | 55.07% | 50.59% | 50.89% | 49.90% | 50.90% | 51.68% | 52.15% | 51.60% |
| Entergy New Orleans, LLC | ETR | 46.31% | 47.60% | 48.31% | 48.81% | 49.07% | 45.98% | 46.57% | 46.84% | 47.44% |
| Entergy Texas, Inc. | ETR | 51.37% | 49.21% | 49.87% | 46.54% | 47.39% | 48.62% | 49.21% | 49.55% | 48.97% |
| Connecticut Light and Power Company | ES | 45.88% | 44.62% | 41.82% | 43.82% | 45.51% | 46.15% | 49.60% | 46.18% | 45.45% |
| NSTAR Electric Company | ES | 46.19% | 47.26% | 43.92% | 44.26% | 44.50% | 45.49% | 46.17% | 46.15% | 45.49% |
| Public Service Company of New Hampshire | ES | 59.36% | 59.98% | 51.62% | 52.08% | 56.89% | 57.94% | 42.07% | 42.70% | 52.83% |
| Western Massachusetts Electric Company | ES | NA | NA | NA | NA | NA | NA | NA | 46.57% | 46.57% |
| Hawaii Electric Light Company, Inc. | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Hawaiian Electric Company, Inc. | HE | 41.57% | 41.83% | 41.94% | 42.02% | 43.91% | 44.22% | 42.56% | 42.58% | 42.58% |
| Maui Electric Company, Limited | HE | NA | NA | NA | NA | NA | NA | NA | NA | NA |
| Idaho Power Company | IDA | 44.80% | 45.42% | 45.64% | 45.75% | 45.75% | 46.56% | 48.63% | 45.78% | 46.04% |
| Madison Gas and Electric Company | MGEE | 40.34% | 41.16% | 41.54% | 42.10% | 42.64% | 39.34% | 39.80% | 40.27% | 40.90% |
| Florida Power & Light Company | NEE | 40.22% | 38.70% | 35.97% | 35.63% | 35.22% | 39.16% | 38.77% | 40.07% | 37.97% |
| Gulf Power Company | NEE | 47.48% | 38.85% | 41.94% | NA | NA | NA | NA | NA | 42.76% |
| NorthWestern Corporation | NWE | 52.20% | 51.93% | 51.26% | 52.12% | 51.64% | 51.59% | 52.52% | 50.11% | 51.67% |
| Oklahoma Gas and Electric Company | OGE | 45.04% | 46.53% | 44.62% | 46.80% | 46.95% | 45.75% | 46.41% | 46.64% | 46.09% |
| Otter Tail Power Company | OTTR | 44.57% | 46.25% | 46.10% | 46.42% | 46.51% | 46.89% | 47.33% | 42.66% | 45.84% |
| Arizona Public Service Company | PNW | 45.75% | 45.59% | 45.52% | 45.64% | 46.32% | 46.29% | 46.82% | 46.86% | 46.10% |
| Public Service Company of New Mexico | PNM | 54.67% | 56.14% | 56.55% | 54.37% | 51.99% | 53.32% | 53.80% | 53.94% | 54.35% |
| Portland General Electric Company | POR | 48.22% | 48.44% | 49.40% | 49.81% | 49.49% | 49.71% | 49.86% | 50.20% | 49.39% |
| Public Service Electric and Gas Company | PEG | 45.35% | 45.69% | 44.86% | 45.76% | 46.31% | 46.07% | 45.80% | 46.59% | 45.80% |
| Oncor Electric Delivery Company LLC | SRE | 45.09% | 42.57% | 40.21% | 40.53% | 40.71% | 37.69% | 39.66% | 41.14% | 40.95% |
| San Diego Gas & Electric Company | SRE | 42.57% | 44.83% | 43.40% | 44.21% | 44.83% | 45.53% | 44.08% | 44.91% | 44.29% |
| Sharyland Utilities, LLC | SRE | NA | NA | 54.95% | 55.38% | 55.08% | 53.61% | 53.66% | 54.14% | 54.47% |
| Alabama Power Company | SO | 48.55% | 47.46% | 47.77% | 52.23% | 51.87% | 52.49% | 51.14% | 52.93% | 50.56% |
| Georgia Power Company | SO | 44.62% | 43.61% | 43.57% | 40.98% | 42.73% | 45.03% | 46.19% | 49.94% | 44.58% |
| Mississippi Power Company | SO | 49.77% | 50.13% | 50.27% | 49.65% | 54.72% | 56.13% | 57.00% | 60.66% | 53.54% |
| Gulf Power Company | SO | NA | NA | NA | 40.27% | 44.66% | 45.10% | 45.73% | 45.81% | 44.31% |
| Upper Michigan Energy Resources Corporation | WEC | 43.91% | 45.55% | 47.46% | 52.99% | 44.92% | 45.47% | 29.96% | 50.15% | 45.05% |
| Wisconsin Electric Power Company | WEC | 43.08% | 43.36% | 44.22% | 43.97% | 40.75% | 40.91% | 43.53% | 44.06% | 42.99% |
| Wisconsin Public Service Corporation | WEC | 45.63% | 40.96% | 41.12% | 42.67% | 39.41% | 40.47% | 41.65% | 41.94% | 41.73% |
| Northern States Power Company - MN | XEL | 48.21% | 46.34% | 46.36% | 47.19% | 47.36% | 47.39% | 47.41% | 47.62% | 47.23% |
| Northern States Power Company - WI | XEL | 46.44% | 46.51% | 46.41% | 46.40% | 51.55% | 46.15% | 46.21% | 46.64% | 47.04% |
| Public Service Company of Colorado | XEL | 43.65% | 42.47% | 43.32% | 43.69% | 43.92% | 45.83% | 43.33% | 43.50% | 43.71% |
| Southwestern Public Service Company | XEL | 45.79% | 45.86% | 45.87% | 45.83% | 43.71% | 46.12% | 46.46% | 46.45% | 45.76% |
| Mean | | 47.46% | 47.50% | 47.35% | 47.51% | 47.55% | 47.73% | 47.39% | 47.73% | 47.48% |

Recently Authorized ROEs by RRA Ranking

| | | | | | | | | Electric Utilities | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **Company** | **Case Identification** | **Service** | **Case Type** | **Date** | **Return on Equity (%)** | **RRA Rank** | **Top Third (Average/1 and higher)** | **Middle Third (Average/2)** | **Bottom Third (Average/3 and lower)** |
| Washington | Avista Corp. | D-UE-150204 | Electric | Vertically Integrated | 1/6/2016 | 9.50 | Average / 3 | | | 9.50 |
| Arkansas | Entergy Arkansas LLC | D-15-015-U | Electric | Vertically Integrated | 2/23/2016 | 9.75 | Average / 3 | | | 9.75 |
| Indiana | Indianapolis Power & Light Co. | Ca-44576 | Electric | Vertically Integrated | 3/16/2016 | 9.85 | Above Average / 3 | 9.85 | | |
| New Mexico | El Paso Electric Co. | C-15-00127-UT | Electric | Vertically Integrated | 6/8/2016 | 9.48 | Below Average / 1 | | | 9.48 |
| Indiana | Northern IN Public Svc Co. | Ca-44688 | Electric | Vertically Integrated | 7/18/2016 | 9.98 | Above Average / 3 | 9.98 | | |
| Tennessee | Kingsport Power Company | D-16-00001 | Electric | Vertically Integrated | 8/9/2016 | 9.85 | Average / 1 | 9.85 | | |
| Arizona | UNS Electric Inc. | D-E-04204A-15-0142 | Electric | Vertically Integrated | 8/18/2016 | 9.50 | Average / 3 | | | 9.50 |
| Washington | PacifiCorp | D-UE-152253 | Electric | Vertically Integrated | 9/1/2016 | 9.50 | Average / 3 | | | 9.50 |
| Michigan | Upper Peninsula Power Co. | C-U-17895 | Electric | Vertically Integrated | 9/8/2016 | 10.00 | Average / 1 | 10.00 | | |
| New Mexico | Public Service Co. of NM | C-15-00261-UT | Electric | Vertically Integrated | 9/28/2016 | 9.58 | Below Average / 1 | | | 9.58 |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-121 (Elec) | Electric | Vertically Integrated | 11/9/2016 | 9.80 | Above Average / 2 | 9.80 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201500208 | Electric | Vertically Integrated | 11/10/2016 | 9.50 | Average / 2 | | 9.50 | |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-120 (Elec) | Electric | Vertically Integrated | 11/18/2016 | 10.00 | Above Average / 2 | 10.00 | | |
| Florida | Florida Power & Light Co. | D-160021-EI | Electric | Vertically Integrated | 11/29/2016 | 10.55 | Above Average / 3 | 10.55 | | |
| California | Lbrty Utilities (CalPeco Elect | A-15-05-008 | Electric | Vertically Integrated | 12/1/2016 | 10.00 | Average / 1 | 10.00 | | |
| South Carolina | Duke Energy Progress LLC | D-2016-227-E | Electric | Vertically Integrated | 12/7/2016 | 10.10 | Average / 1 | 10.10 | | |
| Colorado | Black Hills Colorado Electric | D-16AL-0326E | Electric | Vertically Integrated | 12/19/2016 | 9.37 | Average / 1 | 9.37 | | |
| Nevada | Sierra Pacific Power Co. | D-16-06006 | Electric | Vertically Integrated | 12/22/2016 | 9.60 | Average / 2 | | 9.60 | |
| North Carolina | Virginia Electric & Power Co. | D-E-22, Sub 532 | Electric | Vertically Integrated | 12/22/2016 | 9.90 | Average / 1 | 9.90 | | |
| Idaho | Avista Corp. | C-AVU-E-16-03 | Electric | Vertically Integrated | 12/28/2016 | 9.50 | Average / 2 | | 9.50 | |
| Wyoming | MDU Resources Group Inc. | D-20004-117-ER-16 | Electric | Vertically Integrated | 1/18/2017 | 9.45 | Average / 2 | | 9.45 | |
| Michigan | DTE Electric Co. | C-U-18014 | Electric | Vertically Integrated | 1/31/2017 | 10.10 | Average / 1 | 10.10 | | |
| Arizona | Tucson Electric Power Co. | D-E-01933A-15-0322 | Electric | Vertically Integrated | 2/24/2017 | 9.75 | Average / 3 | | | 9.75 |
| Michigan | Consumers Energy Co. | C-U-17990 | Electric | Vertically Integrated | 2/28/2017 | 10.10 | Average / 1 | 10.10 | | |
| Minnesota | Otter Tail Power Co. | D-E-017/GR-15-1033 | Electric | Vertically Integrated | 3/2/2017 | 9.41 | Average / 2 | | 9.41 | |
| Oklahoma | Oklahoma Gas and Electric Co. | Ca-PUD201500273 | Electric | Vertically Integrated | 3/20/2017 | 9.50 | Average / 2 | | 9.50 | |
| Florida | Gulf Power Co. | D-160186-EI | Electric | Vertically Integrated | 4/4/2017 | 10.25 | Above Average / 3 | 10.25 | | |
| Missouri | Kansas City Power & Light | C-ER-2016-0285 | Electric | Vertically Integrated | 5/3/2017 | 9.50 | Average / 2 | | 9.50 | |
| Minnesota | Northern States Power Co. - MN | D-E-002/GR-15-826 | Electric | Vertically Integrated | 5/11/2017 | 9.20 | Average / 2 | | 9.20 | |
| Arkansas | Oklahoma Gas and Electric Co. | D-16-052-U | Electric | Vertically Integrated | 5/18/2017 | 9.50 | Average / 1 | 9.50 | | |
| North Dakota | MDU Resources Group Inc. | C-PU-16-666 | Electric | Vertically Integrated | 6/16/2017 | 9.65 | Average / 1 | 9.65 | | |
| Kentucky | Kentucky Utilities Co. | C-2016-00370 | Electric | Vertically Integrated | 6/22/2017 | 9.70 | Average / 1 | 9.70 | | |
| Kentucky | Louisville Gas & Electric Co. | C-2016-00371 (elec.) | Electric | Vertically Integrated | 6/22/2017 | 9.70 | Average / 1 | 9.70 | | |
| Arizona | Arizona Public Service Co. | D-E-01345A-16-0036 | Electric | Vertically Integrated | 8/15/2017 | 10.00 | Average / 3 | | | 10.00 |
| California | San Diego Gas & Electric Co. | Advice No. 3120-E | Electric | Vertically Integrated | 10/26/2017 | 10.20 | Above Average / 3 | 10.20 | | |
| California | Pacific Gas and Electric Co. | Advise No. 3887-G/5148-E | Electric | Vertically Integrated | 10/26/2017 | 10.25 | Above Average / 3 | 10.25 | | |
| California | Southern California Edison Co. | Advice No. 3665-E | Electric | Vertically Integrated | 10/26/2017 | 10.30 | Above Average / 3 | 10.30 | | |
| Florida | Tampa Electric Co. | D-20170210-EI | Electric | Vertically Integrated | 11/6/2017 | 10.25 | Above Average / 2 | 10.25 | | |
| Alaska | Alaska Electric Light Power | D-U-16-086 | Electric | Vertically Integrated | 11/15/2017 | 11.95 | Below Average / 1 | | | 11.95 |
| Washington | Puget Sound Energy Inc. | D-UE-170033 | Electric | Vertically Integrated | 12/5/2017 | 9.50 | Average / 3 | | | 9.50 |
| Wisconsin | Northern States Power Co - WI | D-4220-UR-123 (Elec) | Electric | Vertically Integrated | 12/7/2017 | 9.80 | Above Average / 2 | 9.80 | | |
| Texas | Southwestern Electric Power Co | D-46449 | Electric | Vertically Integrated | 12/14/2017 | 9.60 | Average / 3 | | | 9.60 |
| Texas | El Paso Electric Co. | D-46831 | Electric | Vertically Integrated | 12/14/2017 | 9.65 | Average / 3 | | | 9.65 |
| Oregon | Portland General Electric Co. | D-UE-319 | Electric | Vertically Integrated | 12/18/2017 | 9.50 | Average / 2 | | 9.50 | |
| New Mexico | Public Service Co. of NM | C-16-00276-UT | Electric | Vertically Integrated | 12/20/2017 | 9.58 | Below Average / 2 | | | 9.58 |
| Vermont | Green Mountain Power Corp. | C-17-3112-INV | Electric | Vertically Integrated | 12/21/2017 | 9.10 | Average / 2 | | 9.10 | |
| Idaho | Avista Corp. | C-AVU-E-17-01 | Electric | Vertically Integrated | 12/28/2017 | 9.50 | Average / 2 | | 9.50 | |
| Nevada | Nevada Power Co. | D-17-06003 | Electric | Vertically Integrated | 12/29/2017 | 9.51 | Average / 2 | | 9.51 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|
| Kentucky | Kentucky Power Co. | C-2017-00179 | Electric | Vertically Integrated | 1/18/2018 | 9.70 | Average / 1 | 9.70 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201700151 | Electric | Vertically Integrated | 1/31/2018 | 9.30 | Average / 3 | | | 9.30 |
| Iowa | Interstate Power & Light Co. | D-RPU-2017-0001 | Electric | Vertically Integrated | 2/2/2018 | 9.98 | Average / 1 | 9.98 | | |
| North Carolina | Duke Energy Progress LLC | D-E-2, Sub 1142 | Electric | Vertically Integrated | 2/23/2018 | 9.90 | Average / 1 | 9.90 | | |
| Minnesota | ALLETE (Minnesota Power) | D-E-015/GR-16-664 | Electric | Vertically Integrated | 3/12/2018 | 9.25 | Average / 2 | | 9.25 | |
| Michigan | Consumers Energy Co. | C-U-18322 | Electric | Vertically Integrated | 3/29/2018 | 10.00 | Above Average / 3 | 10.00 | | |
| Michigan | Indiana Michigan Power Co. | C-U-18370 | Electric | Vertically Integrated | 4/12/2018 | 9.90 | Above Average / 3 | 9.90 | | |
| Kentucky | Duke Energy Kentucky Inc. | C-2017-00321 | Electric | Vertically Integrated | 4/13/2018 | 9.73 | Average / 1 | 9.73 | | |
| Michigan | DTE Electric Co. | C-U-18255 | Electric | Vertically Integrated | 4/18/2018 | 10.00 | Above Average / 3 | 10.00 | | |
| Washington | Avista Corp. | D-UE-170485 | Electric | Vertically Integrated | 4/26/2018 | 9.50 | Average / 3 | | | 9.50 |
| Indiana | Indiana Michigan Power Co. | Ca-44967 | Electric | Vertically Integrated | 5/30/2018 | 9.95 | Average / 1 | 9.95 | | |
| Hawaii | Hawaiian Electric Co. | D-2016-0328 | Electric | Vertically Integrated | 6/22/2018 | 9.50 | Average / 2 | | 9.50 | |
| North Carolina | Duke Energy Carolinas LLC | D-E-7, Sub 1146 | Electric | Vertically Integrated | 6/22/2018 | 9.90 | Average / 1 | 9.90 | | |
| Hawaii | Hawaii Electric Light Co | D-2015-0170 | Electric | Vertically Integrated | 6/29/2018 | 9.50 | Average / 2 | | 9.50 | |
| New Mexico | Southwestern Public Service Co | C-17-00255-UT | Electric | Vertically Integrated | 9/5/2018 | 9.56 | Below Average / 2 | | | 9.56 |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-121 (Elec) | Electric | Vertically Integrated | 9/14/2018 | 10.00 | Above Average / 2 | 10.00 | | |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-122 (Elec) | Electric | Vertically Integrated | 9/20/2018 | 9.80 | Above Average / 2 | 9.80 | | |
| North Dakota | Otter Tail Power Co. | C-PU-17-398 | Electric | Vertically Integrated | 9/26/2018 | 9.77 | Average / 1 | 9.77 | | |
| Kansas | Westar Energy Inc. | D-18-WSEE-328-RTS | Electric | Vertically Integrated | 9/27/2018 | 9.30 | Below Average / 1 | | | 9.30 |
| Indiana | Indianapolis Power & Light Co. | Ca-45029 | Electric | Vertically Integrated | 10/31/2018 | 9.99 | Average / 1 | 9.99 | | |
| Kansas | Kansas City Power & Light | D-18-KCPE-480-RTS | Electric | Vertically Integrated | 12/13/2018 | 9.30 | Below Average / 1 | | | 9.30 |
| Oregon | Portland General Electric Co. | D-UE-335 | Electric | Vertically Integrated | 12/14/2018 | 9.50 | Average / 2 | | 9.50 | |
| Michigan | Consumers Energy Co. | C-U-20134 | Electric | Vertically Integrated | 1/9/2019 | 10.00 | Above Average / 3 | 10.00 | | |
| West Virginia | Appalachian Power Co. | C-18-0646-E-42T | Electric | Vertically Integrated | 2/27/2019 | 9.75 | Below Average / 2 | | | 9.75 |
| Oklahoma | Public Service Co. of OK | Ca-PUD201800097 | Electric | Vertically Integrated | 3/14/2019 | 9.40 | Average / 3 | | | 9.40 |
| Kentucky | Kentucky Utilities Co. | C-2018-00294 | Electric | Vertically Integrated | 4/30/2019 | 9.73 | Average / 1 | 9.73 | | |
| Kentucky | Louisville Gas & Electric Co. | C-2018-00295 (elec.) | Electric | Vertically Integrated | 4/30/2019 | 9.73 | Average / 1 | 9.73 | | |
| South Carolina | Duke Energy Carolinas LLC | D-2018-319-E | Electric | Vertically Integrated | 5/1/2019 | 9.50 | Average / 3 | | | 9.50 |
| Michigan | DTE Electric Co. | C-U-20162 | Electric | Vertically Integrated | 5/2/2019 | 10.00 | Above Average / 3 | 10.00 | | |
| South Carolina | Duke Energy Progress LLC | D-2018-318-E | Electric | Vertically Integrated | 5/8/2019 | 9.50 | Average / 3 | | | 9.50 |
| South Dakota | Otter Tail Power Co. | D-EL18-021 | Electric | Vertically Integrated | 5/14/2019 | 8.75 | Average / 2 | | 8.75 | |
| Hawaii | Maui Electric Company Ltd | D-2017-0150 | Electric | Vertically Integrated | 5/16/2019 | 9.50 | Average / 2 | | 9.50 | |
| Michigan | Upper Peninsula Power Co. | C-U-20276 | Electric | Vertically Integrated | 5/23/2019 | 9.90 | Above Average / 3 | 9.90 | | |
| Vermont | Green Mountain Power Corp. | C-19-1932-TF | Electric | Vertically Integrated | 8/29/2019 | 9.06 | Average / 3 | | | 9.06 |
| Wisconsin | Northern States Power Co - WI | D- 4220-UR-124 (Elec) | Electric | Vertically Integrated | 9/4/2019 | 10.00 | Above Average / 2 | 10.00 | | |
| Montana | NorthWestern Corp. | D2018.2.12 | Electric | Vertically Integrated | 12/20/2019 | 9.65 | Below Average / 1 | | | 9.65 |
| Wisconsin | Wisconsin Electric Power Co. | D-05-UR-109 (WEP-Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | Above Average / 2 | 10.00 | | |
| Wisconsin | Wisconsin Public Service Corp. | D-6690-UR-126 (Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | Above Average / 2 | 10.00 | | |
| Louisiana - NOCC | Entergy New Orleans LLC | D-UD-18-07 (elec.) | Electric | Vertically Integrated | 11/7/2019 | 9.35 | Average / 2 | | 9.35 | |
| Idaho | Avista Corp. | C-AVU-E-1904 | Electric | Vertically Integrated | 11/29/2019 | 9.50 | Average / 2 | | 9.50 | |
| Indiana | Northern IN Public Svc Co. | Ca-45159 | Electric | Vertically Integrated | 12/4/2019 | 9.75 | Average / 1 | 9.75 | | |
| Georgia | Georgia Power Co. | D-42516 | Electric | Vertically Integrated | 12/17/2019 | 10.50 | Above Average / 2 | 10.50 | | |
| California | San Diego Gas & Electric Co. | A-19-04-017 (Elec) | Electric | Vertically Integrated | 12/19/2019 | 10.20 | Average / 2 | | 10.20 | |
| California | Pacific Gas and Electric Co. | A-19-04-015 | Electric | Vertically Integrated | 12/19/2019 | 10.25 | Average / 2 | | 10.25 | |
| California | Southern California Edison Co. | A-19-04-014 | Electric | Vertically Integrated | 12/19/2019 | 10.30 | Average / 2 | | 10.30 | |
| Arkansas | Southwestern Electric Power Co | D-19-008-U | Electric | Vertically Integrated | 12/20/2019 | 9.45 | Average / 1 | 9.45 | | |
| Montana | NorthWestern Corp. | D2018.2.12 | Electric | Vertically Integrated | 12/20/2019 | 9.65 | Below Average / 1 | | | 9.65 |
| Nevada | Sierra Pacific Power Co. | D-19-06002 | Electric | Vertically Integrated | 12/24/2019 | 9.50 | Average / 2 | | 9.50 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|
| Iowa | Interstate Power & Light Co. | D-RPU-2019-0001 | Electric | Vertically Integrated | 1/8/2020 | 10.02 | Average / 1 | 10.02 | | |
| Michigan | Indiana Michigan Power Co. | C-U-20359 | Electric | Vertically Integrated | 1/23/2020 | 9.86 | Above Average / 3 | 9.86 | | |
| California | PacifiCorp | A-18-04-002 | Electric | Vertically Integrated | 2/6/2020 | 10.00 | Average / 2 | | 10.00 | |
| Colorado | Public Service Co. of CO | D-19AL-0268E | Electric | Vertically Integrated | 2/11/2020 | 9.30 | Average / 2 | | 9.30 | |
| North Carolina | Virginia Electric & Power Co. | E-22, Sub 562 | Electric | Vertically Integrated | 2/24/2020 | 9.75 | Average / 1 | 9.75 | | |
| Indiana | Indiana Michigan Power Co. | Ca-45235 | Electric | Vertically Integrated | 3/11/2020 | 9.70 | Average / 1 | 9.70 | | |
| Washington | Avista Corp. | D-UE-190334 | Electric | Vertically Integrated | 3/25/2020 | 9.40 | Average / 3 | | | 9.40 |
| | | | | | Total Cases | 103 | | 49 | 24 | 25 |
| | | | | | Mean | 9.75 | | 9.93 | 9.53 | 9.62 |
| | | | | | Median | 9.73 | | 9.95 | 9.50 | 9.50 |
| | | | | | Maximum | 11.95 | | 10.55 | 10.30 | 11.95 |
| | | | | | Minimum | 8.75 | | 9.37 | 8.75 | 9.06 |
| | | | | | 2019 Mean | 9.73 | | | | |
| | | | | | 2019 Median | 9.73 | | | | |

Source: Regulatory Research Associates

**CERTIFICATE OF SERVICE**

DOCKET NO. E-2, SUB 1219

I hereby certify that a copy of the foregoing **AMENDED REBUTTAL TESTIMONY AND EXHIBITS OF DYLAN W. D'ASCENDIS** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 7th day of July, 2020.

**DUKE ENERGY PROGRESS, LLC**

*/s/ Kiran H. Mehta*
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ATTORNEY FOR DUKE ENERGY PROGRESS, LLC

Recently Authorized ROEs by RRA Ranking

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | Equity Ratio (%) | RRA Rank | Authorized ROE: Top Third (Average/1 and higher) | Authorized ROE: Middle Third (Average/2) | Authorized ROE: Bottom Third (Average/3 and lower) | Authorized Equity Ratio: Top Third (Average/1 and higher) | Authorized Equity Ratio: Middle Third (Average/2) | Authorized Equity Ratio: Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Washington | Avista Corp. | D-UE-150204 | Electric | Vertically Integrated | 1/6/2016 | 9.50 | 48.50 | Average / 3 | | | 9.50 | | | 48.50 |
| Arkansas | Entergy Arkansas LLC | D-15-015-U | Electric | Vertically Integrated | 2/23/2016 | 9.75 | NA | Average / 3 | | | 9.75 | | | NA |
| Indiana | Indianapolis Power & Light Co. | Ca-44576 | Electric | Vertically Integrated | 3/16/2016 | 9.85 | NA | Above Average / 3 | 9.85 | | | NA | | |
| New Mexico | El Paso Electric Co. | C-15-00127-UT | Electric | Vertically Integrated | 6/8/2016 | 9.48 | 49.29 | Below Average / 1 | | | 9.48 | | | 49.29 |
| Indiana | Northern IN Public Svc Co. | Ca-44688 | Electric | Vertically Integrated | 7/18/2016 | 9.98 | NA | Above Average / 3 | 9.98 | | | NA | | |
| Tennessee | Kingsport Power Company | D-16-00001 | Electric | Vertically Integrated | 8/9/2016 | 9.85 | 40.25 | Average / 1 | 9.85 | | | 40.25 | | |
| Arizona | UNS Electric Inc. | D-E-04204A-15-0142 | Electric | Vertically Integrated | 8/18/2016 | 9.50 | 52.83 | Average / 3 | | | 9.50 | | | 52.83 |
| Washington | PacifiCorp | D-UE-152253 | Electric | Vertically Integrated | 9/1/2016 | 9.50 | 49.10 | Average / 3 | | | 9.50 | | | 49.10 |
| Michigan | Upper Peninsula Power Co. | C-U-17895 | Electric | Vertically Integrated | 9/8/2016 | 10.00 | NA | Average / 1 | 10.00 | | | NA | | |
| New Mexico | Public Service Co. of NM | C-15-00261-UT | Electric | Vertically Integrated | 9/28/2016 | 9.58 | 49.61 | Below Average / 1 | | | 9.58 | | | 49.61 |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-121 (Elec) | Electric | Vertically Integrated | 11/9/2016 | 9.80 | 57.16 | Above Average / 2 | 9.80 | | | 57.16 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201500208 | Electric | Vertically Integrated | 11/10/2016 | 9.50 | 44.00 | Average / 2 | | 9.50 | | | 44.00 | |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-120 (Elec) | Electric | Vertically Integrated | 11/18/2016 | 10.00 | 52.20 | Above Average / 2 | 10.00 | | | 52.20 | | |
| Florida | Florida Power & Light Co. | D-160021-EI | Electric | Vertically Integrated | 11/29/2016 | 10.55 | NA | Above Average / 3 | 10.55 | | | NA | | |
| California | Lbrty Utilities (CalPeco Elect | A-15-05-008 | Electric | Vertically Integrated | 12/1/2016 | 10.00 | 52.50 | Average / 1 | 10.00 | | | 52.50 | | |
| South Carolina | Duke Energy Progress LLC | D-2016-227-E | Electric | Vertically Integrated | 12/7/2016 | 10.10 | 53.00 | Average / 1 | 10.10 | | | 53.00 | | |
| Colorado | Black Hills Colorado Electric | D-16AL-0326E | Electric | Vertically Integrated | 12/19/2016 | 9.37 | 52.39 | Average / 1 | 9.37 | | | 52.39 | | |
| Nevada | Sierra Pacific Power Co. | D-16-06006 | Electric | Vertically Integrated | 12/22/2016 | 9.60 | 48.03 | Average / 2 | | 9.60 | | | 48.03 | |
| North Carolina | Virginia Electric & Power Co. | D-E-22, Sub 532 | Electric | Vertically Integrated | 12/22/2016 | 9.90 | 51.75 | Average / 1 | 9.90 | | | 51.75 | | |
| Idaho | Avista Corp. | C-AVU-E-16-03 | Electric | Vertically Integrated | 12/28/2016 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Wyoming | MDU Resources Group Inc. | D-20004-117-ER-16 | Electric | Vertically Integrated | 1/18/2017 | 9.45 | 50.99 | Average / 2 | | 9.45 | | | 50.99 | |
| Michigan | DTE Electric Co. | C-U-18014 | Electric | Vertically Integrated | 1/31/2017 | 10.10 | NA | Average / 1 | 10.10 | | | NA | | |
| Arizona | Tucson Electric Power Co. | D-E-01933A-15-0322 | Electric | Vertically Integrated | 2/24/2017 | 9.75 | 50.03 | Average / 3 | | | 9.75 | | | 50.03 |
| Michigan | Consumers Energy Co. | C-U-17990 | Electric | Vertically Integrated | 2/28/2017 | 10.10 | NA | Average / 1 | 10.10 | | | NA | | |
| Minnesota | Otter Tail Power Co. | D-E-017/GR-15-1033 | Electric | Vertically Integrated | 3/2/2017 | 9.41 | 52.50 | Average / 2 | | 9.41 | | | 52.50 | |
| Oklahoma | Oklahoma Gas and Electric Co. | Ca-PUD201500273 | Electric | Vertically Integrated | 3/20/2017 | 9.50 | 53.31 | Average / 2 | | 9.50 | | | 53.31 | |
| Florida | Gulf Power Co. | D-160186-EI | Electric | Vertically Integrated | 4/4/2017 | 10.25 | NA | Above Average / 3 | 10.25 | | | NA | | |
| Missouri | Kansas City Power & Light | C-ER-2016-0285 | Electric | Vertically Integrated | 5/3/2017 | 9.50 | 49.20 | Average / 2 | | 9.50 | | | 49.20 | |
| Minnesota | Northern States Power Co. - MN | D-E-002/GR-15-826 | Electric | Vertically Integrated | 5/11/2017 | 9.20 | 52.50 | Average / 2 | | 9.20 | | | 52.50 | |
| Arkansas | Oklahoma Gas and Electric Co. | D-16-052-U | Electric | Vertically Integrated | 5/18/2017 | 9.50 | NA | Average / 1 | 9.50 | | | NA | | |
| North Dakota | MDU Resources Group Inc. | C-PU-16-666 | Electric | Vertically Integrated | 6/16/2017 | 9.65 | 51.40 | Average / 1 | 9.65 | | | 51.40 | | |
| Kentucky | Kentucky Utilities Co. | C-2016-00370 | Electric | Vertically Integrated | 6/22/2017 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| Kentucky | Louisville Gas & Electric Co. | C-2016-00371 (elec.) | Electric | Vertically Integrated | 6/22/2017 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| Arizona | Arizona Public Service Co. | D-E-01345A-16-0036 | Electric | Vertically Integrated | 8/15/2017 | 10.00 | 55.80 | Average / 3 | | | 10.00 | | | 55.80 |
| California | San Diego Gas & Electric Co. | Advice No. 3120-E | Electric | Vertically Integrated | 10/26/2017 | 10.20 | 52.00 | Above Average / 3 | 10.20 | | | 52.00 | | |
| California | Pacific Gas and Electric Co. | Advise No. 3887-G/5148-E | Electric | Vertically Integrated | 10/26/2017 | 10.25 | 52.00 | Above Average / 3 | 10.25 | | | 52.00 | | |
| California | Southern California Edison Co. | Advice No. 3665-E | Electric | Vertically Integrated | 10/26/2017 | 10.30 | 48.00 | Above Average / 3 | 10.30 | | | 48.00 | | |
| Florida | Tampa Electric Co. | D-20170210-EI | Electric | Vertically Integrated | 11/6/2017 | 10.25 | NA | Above Average / 2 | 10.25 | | | NA | | |
| Alaska | Alaska Electric Light Power | D-U-16-086 | Electric | Vertically Integrated | 11/15/2017 | 11.95 | 58.18 | Below Average / 1 | | | 11.95 | | | 58.18 |
| Washington | Puget Sound Energy Inc. | D-UE-170033 | Electric | Vertically Integrated | 12/5/2017 | 9.50 | 48.50 | Average / 3 | | | 9.50 | | | 48.50 |
| Wisconsin | Northern States Power Co - WI | D-4220-UR-123 (Elec) | Electric | Vertically Integrated | 12/7/2017 | 9.80 | 51.45 | Above Average / 2 | 9.80 | | | 51.45 | | |
| Texas | Southwestern Electric Power Co | D-46449 | Electric | Vertically Integrated | 12/14/2017 | 9.60 | 48.46 | Average / 3 | | | 9.60 | | | 48.46 |
| Texas | El Paso Electric Co. | D-46831 | Electric | Vertically Integrated | 12/14/2017 | 9.65 | 48.35 | Average / 3 | | | 9.65 | | | 48.35 |
| Oregon | Portland General Electric Co. | D-UE-319 | Electric | Vertically Integrated | 12/18/2017 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| New Mexico | Public Service Co. of NM | C-16-00276-UT | Electric | Vertically Integrated | 12/20/2017 | 9.58 | 49.61 | Below Average / 2 | | | 9.58 | | | 49.61 |
| Vermont | Green Mountain Power Corp. | C-17-3112-INV | Electric | Vertically Integrated | 12/21/2017 | 9.10 | 48.60 | Average / 2 | | 9.10 | | | 48.60 | |
| Idaho | Avista Corp. | C-AVU-E-17-01 | Electric | Vertically Integrated | 12/28/2017 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Nevada | Nevada Power Co. | D-17-06003 | Electric | Vertically Integrated | 12/29/2017 | 9.51 | 49.99 | Average / 2 | | 9.51 | | | 49.99 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | Equity Ratio (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Kentucky | Kentucky Power Co. | C-2017-00179 | Electric | Vertically Integrated | 1/18/2018 | 9.70 | 41.68 | Average / 1 | 9.70 | | | 41.68 | | |
| Oklahoma | Public Service Co. of OK | Ca-PUD201700151 | Electric | Vertically Integrated | 1/31/2018 | 9.30 | 48.51 | Average / 3 | | | 9.30 | | | 48.51 |
| Iowa | Interstate Power & Light Co. | D-RPU-2017-0001 | Electric | Vertically Integrated | 2/2/2018 | 9.98 | 49.02 | Average / 1 | 9.98 | | | 49.02 | | |
| North Carolina | Duke Energy Progress LLC | D-E-2, Sub 1142 | Electric | Vertically Integrated | 2/23/2018 | 9.90 | 52.00 | Average / 1 | 9.90 | | | 52.00 | | |
| Minnesota | ALLETE (Minnesota Power) | D-E-015/GR-16-664 | Electric | Vertically Integrated | 3/12/2018 | 9.25 | 53.81 | Average / 2 | | 9.25 | | | 53.81 | |
| Michigan | Consumers Energy Co. | C-U-18322 | Electric | Vertically Integrated | 3/29/2018 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| Michigan | Indiana Michigan Power Co. | C-U-18370 | Electric | Vertically Integrated | 4/12/2018 | 9.90 | NA | Above Average / 3 | 9.90 | | | NA | | |
| Kentucky | Duke Energy Kentucky Inc. | C-2017-00321 | Electric | Vertically Integrated | 4/13/2018 | 9.73 | 49.25 | Average / 1 | 9.73 | | | 49.25 | | |
| Michigan | DTE Electric Co. | C-U-18255 | Electric | Vertically Integrated | 4/18/2018 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| Washington | Avista Corp. | D-UE-170485 | Electric | Vertically Integrated | 4/26/2018 | 9.50 | 48.50 | Average / 3 | | | 9.50 | | | 48.50 |
| Indiana | Indiana Michigan Power Co. | Ca-44967 | Electric | Vertically Integrated | 5/30/2018 | 9.95 | NA | Average / 1 | 9.95 | | | NA | | |
| Hawaii | Hawaiian Electric Co. | D-2016-0328 | Electric | Vertically Integrated | 6/22/2018 | 9.50 | 57.10 | Average / 2 | | 9.50 | | | 57.10 | |
| North Carolina | Duke Energy Carolinas LLC | D-E-7, Sub 1146 | Electric | Vertically Integrated | 6/22/2018 | 9.90 | 52.00 | Average / 1 | 9.90 | | | 52.00 | | |
| Hawaii | Hawaii Electric Light Co | D-2015-0170 | Electric | Vertically Integrated | 6/29/2018 | 9.50 | 56.69 | Average / 2 | | 9.50 | | | 56.69 | |
| New Mexico | Southwestern Public Service Co | C-17-00255-UT | Electric | Vertically Integrated | 9/5/2018 | 9.56 | 53.97 | Below Average / 2 | | | 9.56 | | | 53.97 |
| Wisconsin | Wisconsin Power and Light Co | D-6680-UR-121 (Elec) | Electric | Vertically Integrated | 9/14/2018 | 10.00 | 52.00 | Above Average / 2 | 10.00 | | | 52.00 | | |
| Wisconsin | Madison Gas and Electric Co. | D-3270-UR-122 (Elec) | Electric | Vertically Integrated | 9/20/2018 | 9.80 | 56.06 | Above Average / 2 | 9.80 | | | 56.06 | | |
| North Dakota | Otter Tail Power Co. | C-PU-17-398 | Electric | Vertically Integrated | 9/26/2018 | 9.77 | 52.50 | Average / 1 | 9.77 | | | 52.50 | | |
| Kansas | Westar Energy Inc. | D-18-WSEE-328-RTS | Electric | Vertically Integrated | 9/27/2018 | 9.30 | 51.24 | Below Average / 1 | | | 9.30 | | | 51.24 |
| Indiana | Indianapolis Power & Light Co. | Ca-45029 | Electric | Vertically Integrated | 10/31/2018 | 9.99 | NA | Average / 1 | 9.99 | | | NA | | |
| Kansas | Kansas City Power & Light | D-18-KCPE-480-RTS | Electric | Vertically Integrated | 12/13/2018 | 9.30 | 49.09 | Below Average / 1 | | | 9.30 | | | 49.09 |
| Oregon | Portland General Electric Co. | D-UE-335 | Electric | Vertically Integrated | 12/14/2018 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Vermont | Green Mountain Power Corp. | C-18-0974-TF | Electric | Vertically Integrated | 12/21/2018 | 9.30 | 49.85 | Average / 3 | | | 9.30 | | | 49.85 |
| Michigan | Consumers Energy Co. | C-U-20134 | Electric | Vertically Integrated | 1/9/2019 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| West Virginia | Appalachian Power Co. | C-18-0646-E-42T | Electric | Vertically Integrated | 2/27/2019 | 9.75 | 50.16 | Below Average / 2 | | | 9.75 | | | 50.16 |
| Oklahoma | Public Service Co. of OK | Ca-PUD201800097 | Electric | Vertically Integrated | 3/14/2019 | 9.40 | NA | Average / 3 | | | 9.40 | | | NA |
| Kentucky | Kentucky Utilities Co. | C-2018-00294 | Electric | Vertically Integrated | 4/30/2019 | 9.73 | NA | Average / 1 | 9.73 | | | NA | | |
| Kentucky | Louisville Gas & Electric Co. | C-2018-00295 (elec.) | Electric | Vertically Integrated | 4/30/2019 | 9.73 | NA | Average / 1 | 9.73 | | | NA | | |
| South Carolina | Duke Energy Carolinas LLC | D-2018-319-E | Electric | Vertically Integrated | 5/1/2019 | 9.50 | 53.00 | Average / 3 | | | 9.50 | | | 53.00 |
| Michigan | DTE Electric Co. | C-U-20162 | Electric | Vertically Integrated | 5/2/2019 | 10.00 | NA | Above Average / 3 | 10.00 | | | NA | | |
| South Carolina | Duke Energy Progress LLC | D-2018-318-E | Electric | Vertically Integrated | 5/8/2019 | 9.50 | 53.00 | Average / 3 | | | 9.50 | | | 53.00 |
| South Dakota | Otter Tail Power Co. | D-EL18-021 | Electric | Vertically Integrated | 5/14/2019 | 8.75 | 52.92 | Average / 2 | | 8.75 | | | 52.92 | |
| Hawaii | Maui Electric Company Ltd | D-2017-0150 | Electric | Vertically Integrated | 5/16/2019 | 9.50 | 57.02 | Average / 2 | | 9.50 | | | 57.02 | |
| Michigan | Upper Peninsula Power Co. | C-U-20276 | Electric | Vertically Integrated | 5/23/2019 | 9.90 | NA | Above Average / 3 | 9.90 | | | NA | | |
| Vermont | Green Mountain Power Corp. | C-19-1932-TF | Electric | Vertically Integrated | 8/29/2019 | 9.06 | 49.46 | Average / 3 | | | 9.06 | | | 49.46 |
| Wisconsin | Northern States Power Co - WI | D- 4220-UR-124 (Elec) | Electric | Vertically Integrated | 9/4/2019 | 10.00 | 52.52 | Above Average / 2 | 10.00 | | | 52.52 | | |
| Wisconsin | Wisconsin Electric Power Co. | D-05-UR-109 (WEP-Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | 54.46 | Above Average / 2 | 10.00 | | | 54.46 | | |
| Wisconsin | Wisconsin Public Service Corp. | D-6690-UR-126 (Elec) | Electric | Vertically Integrated | 10/31/2019 | 10.00 | 51.96 | Above Average / 2 | 10.00 | | | 51.96 | | |
| Louisiana - NOCC | Entergy New Orleans LLC | D-UD-18-07 (elec.) | Electric | Vertically Integrated | 11/7/2019 | 9.35 | 50.00 | Average / 2 | | 9.35 | | | 50.00 | |
| Idaho | Avista Corp. | C-AVU-E-1904 | Electric | Vertically Integrated | 11/29/2019 | 9.50 | 50.00 | Average / 2 | | 9.50 | | | 50.00 | |
| Indiana | Northern IN Public Svc Co. | Ca-45159 | Electric | Vertically Integrated | 12/4/2019 | 9.75 | NA | Average / 1 | 9.75 | | | NA | | |
| Georgia | Georgia Power Co. | D-42516 | Electric | Vertically Integrated | 12/17/2019 | 10.50 | 56.00 | Above Average / 2 | 10.50 | | | 56.00 | | |
| California | San Diego Gas & Electric Co. | A-19-04-017 (Elec) | Electric | Vertically Integrated | 12/19/2019 | 10.20 | 52.00 | Average / 2 | | 10.20 | | | 52.00 | |
| California | Pacific Gas and Electric Co. | A-19-04-015 | Electric | Vertically Integrated | 12/19/2019 | 10.25 | 52.00 | Average / 2 | | 10.25 | | | 52.00 | |
| California | Southern California Edison Co. | A-19-04-014 | Electric | Vertically Integrated | 12/19/2019 | 10.30 | 52.00 | Average / 2 | | 10.30 | | | 52.00 | |
| Arkansas | Southwestern Electric Power Co | D-19-008-U | Electric | Vertically Integrated | 12/20/2019 | 9.45 | NA | Average / 1 | 9.45 | | | NA | | |
| Montana | NorthWestern Corp. | D2018.2.12 | Electric | Vertically Integrated | 12/20/2019 | 9.65 | 49.38 | Below Average / 1 | | | 9.65 | | | 49.38 |
| Nevada | Sierra Pacific Power Co. | D-19-06002 | Electric | Vertically Integrated | 12/24/2019 | 9.50 | 50.92 | Average / 2 | | 9.50 | | | 50.92 | |

| State | Company | Case Identification | Service | Case Type | Date | Return on Equity (%) | Equity Ratio (%) | RRA Rank | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) | Top Third (Average/1 and higher) | Middle Third (Average/2) | Bottom Third (Average/3 and lower) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Iowa | Interstate Power & Light Co. | D-RPU-2019-0001 | Electric | Vertically Integrated | 1/8/2020 | 10.02 | 51.00 | Average / 1 | 10.02 | | | 51.00 | | |
| Michigan | Indiana Michigan Power Co. | C-U-20359 | Electric | Vertically Integrated | 1/23/2020 | 9.86 | NA | Above Average / 3 | 9.86 | | | NA | | |
| California | PacifiCorp | A-18-04-002 | Electric | Vertically Integrated | 2/6/2020 | 10.00 | 51.96 | Average / 2 | | 10.00 | | | 51.96 | |
| Colorado | Public Service Co. of CO | D-19AL-0268E | Electric | Vertically Integrated | 2/11/2020 | 9.30 | 55.61 | Average / 2 | | 9.30 | | | 55.61 | |
| North Carolina | Virginia Electric & Power Co. | E-22, Sub 562 | Electric | Vertically Integrated | 2/24/2020 | 9.75 | 52.00 | Average / 1 | 9.75 | | | 52.00 | | |
| Indiana | Indiana Michigan Power Co. | Ca-45235 | Electric | Vertically Integrated | 3/11/2020 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| Washington | Avista Corp. | D-UE-190334 | Electric | Vertically Integrated | 3/25/2020 | 9.40 | 48.50 | Average / 3 | | | 9.40 | | | 48.50 |
| Kentucky | Duke Energy Kentucky Inc. | C-2019-00271 | Electric | Vertically Integrated | 4/27/2020 | 9.25 | 48.23 | Average / 1 | 9.25 | | | 48.23 | | |
| Michigan | DTE Electric Co. | C-U-20561 | Electric | Vertically Integrated | 5/8/2020 | 9.90 | NA | Above Average / 3 | 9.90 | | | NA | | |
| New Mexico | Southwestern Public Service Co | C-19-00170-UT | Electric | Vertically Integrated | 5/20/2020 | 9.45 | 54.77 | Below Average / 2 | | | 9.45 | | | 54.77 |
| Indiana | Duke Energy Indiana, LLC | Ca-45253 | Electric | Vertically Integrated | 6/29/2020 | 9.70 | NA | Average / 1 | 9.70 | | | NA | | |
| | | | | | Total Cases | 107 | | | 54 | 26 | 27 | 27 | 26 | 25 |
| | | | | | Mean | 9.74 | 51.20 | | 9.91 | 9.53 | 9.60 | 51.29 | 51.58 | 50.71 |
| | | | | | Median | 9.70 | 51.43 | | 9.90 | 9.50 | 9.50 | 52.00 | 51.48 | 49.61 |
| | | | | | Maximum | 11.95 | 58.18 | | 10.55 | 10.30 | 11.95 | 57.16 | 57.10 | 58.18 |
| | | | | | Minimum | 8.75 | 40.25 | | 9.25 | 8.75 | 9.06 | 40.25 | 44.00 | 48.35 |
| | | | | | # >=9.60% | 63 | | | | | | | | |

Source: Regulatory Research Associates
Note: Authorized equity ratios from Arkansas, Florida, Indiana, and Michigan have been excluded from the equity ratio analysis

DUKE ENERGY® PROGRESS

CHARLOTTE, NORTH CAROLINA

# 2018 DEPRECIATION STUDY

## CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2018

*Prepared by:*

Gannett Fleming

*Excellence Delivered* ***As Promised***

DUKE ENERGY PROGRESS

Charlotte, North Carolina

# 2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2018

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Harrisburg, Pennsylvania

I/A

Gannett Fleming

*Excellence Delivered* ***As Promised***



October 15, 2019

Duke Energy Progress
550 S. Tryon Street
Charlotte, NC 28202

Attention: David L. Doss, Jr.
Director Asset Accounting

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Duke Energy Progress as of December 31, 2018. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John J. Spanos

JOHN J. SPANOS
President

JJS:mle

065709

Gannett Fleming Valuation and Rate Consultants, LLC
P.O. Box 67100 • Harrisburg, PA 17106-7100 | 207 Senate Avenue • Camp Hill, PA 17011-2316
t: 717.763.7211 • f: 717.763.4590

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# DUKE ENERGY PROGRESS

# DEPRECIATION STUDY

## EXECUTIVE SUMMARY

Pursuant to Duke Energy Progress' ("DEP" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric plant as of December 31, 2018. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, and forecasted net salvage characteristics for each depreciable group of assets.

The depreciation study results in an overall increase in depreciation expense. This is primarily related to three factors which affect production plant accounts. There is a net increase in depreciation expense for transmission, distribution and general plant accounts, which is the result of changes in service lives or net salvage estimates for some accounts. The increase in depreciation expense for production plant accounts is the result of capital additions and replacements of components of many of the Company's power plants, shorter life span estimates for some of the Company's production plant facilities, and full consideration of all decommissioning study costs that provides an estimate of the future cost to retire the Company's production facilities. These changes produce the most appropriate depreciation rates for the Company's production plant accounts, but result in a necessary increase in depreciation expense in order to ensure the recovery of the Company's investments.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric plant in service as of December 31, 2018 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $950.4 million when applied to depreciable plant balances as of December 31, 2018. The results are summarized at the functional level as follows:

**SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS**

| FUNCTION | ORIGINAL COST AS OF DECEMBER 31, 2018 | PROPOSED RATE | PROPOSED EXPENSE |
|---|---|---|---|
| Steam Production Plant | $3,978,949,911.10 | 5.33 | $212,170,895 |
| Nuclear Production Plant | 8,840,958,165.58 | 3.31 | 292,257,258 |
| Hydraulic Production Plant | 140,864,658.94 | 3.70 | 5,213,027 |
| Other Production Plant | 3,126,769,436.62 | 5.08 | 158,732,404 |
| Transmission Plant | 2,555,572,839.38 | 2.23 | 57,110,744 |
| Distribution Plant | 6,869,268,718.39 | 2.44 | 167,607,654 |
| General Plant | 620,468,150.39 | 5.74 | 35,638,485 |
| Land Rights | 265,099,636.88 | 1.18 | 3,123,751 |
| General Plant Reserve Amortization | - | - | 18,529,294 |
| **Total Depreciable Plant** | **$26,397,951,517.28** | | **$950,383,512** |

# PART I. INTRODUCTION

# DUKE ENERGY PROGRESS
# DEPRECIATION STUDY

## PART I. INTRODUCTION

### SCOPE

This report sets forth the results of the depreciation study for Duke Energy Progress ("Company"), as applied to specific electric plant in service as of December 31, 2018. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to current electric plant in service.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2018; the net salvage analyses of historical plant retirement data recorded through 2018; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

### PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life study. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

## BASIS OF THE STUDY

### Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For all accounts, the annual depreciation was calculated by the straight line method using the average service life procedure and the remaining life basis. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. Amortization accounting or vintage pooling is proposed for most general plant accounts.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use.

**Service Life and Net Salvage Estimates**

The service life and net salvage estimates used in the depreciation calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts. For steam, hydraulic and other production plants, the life span technique was used. In this technique, the date of final retirement was estimated for each unit, and the estimated survivor curves applied to each vintage were truncated at ages coinciding with the date of final retirement.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The estimates of net salvage by account incorporated a review of experienced costs of removal and salvage related to plant retirements, and consideration of trends exhibited by the historical data. Each component of net salvage, i.e., cost of removal and salvage, was stated in dollars and as a percent of retirement.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

# PART II. ESTIMATION OF SURVIVOR CURVES

## PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

### SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

## Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

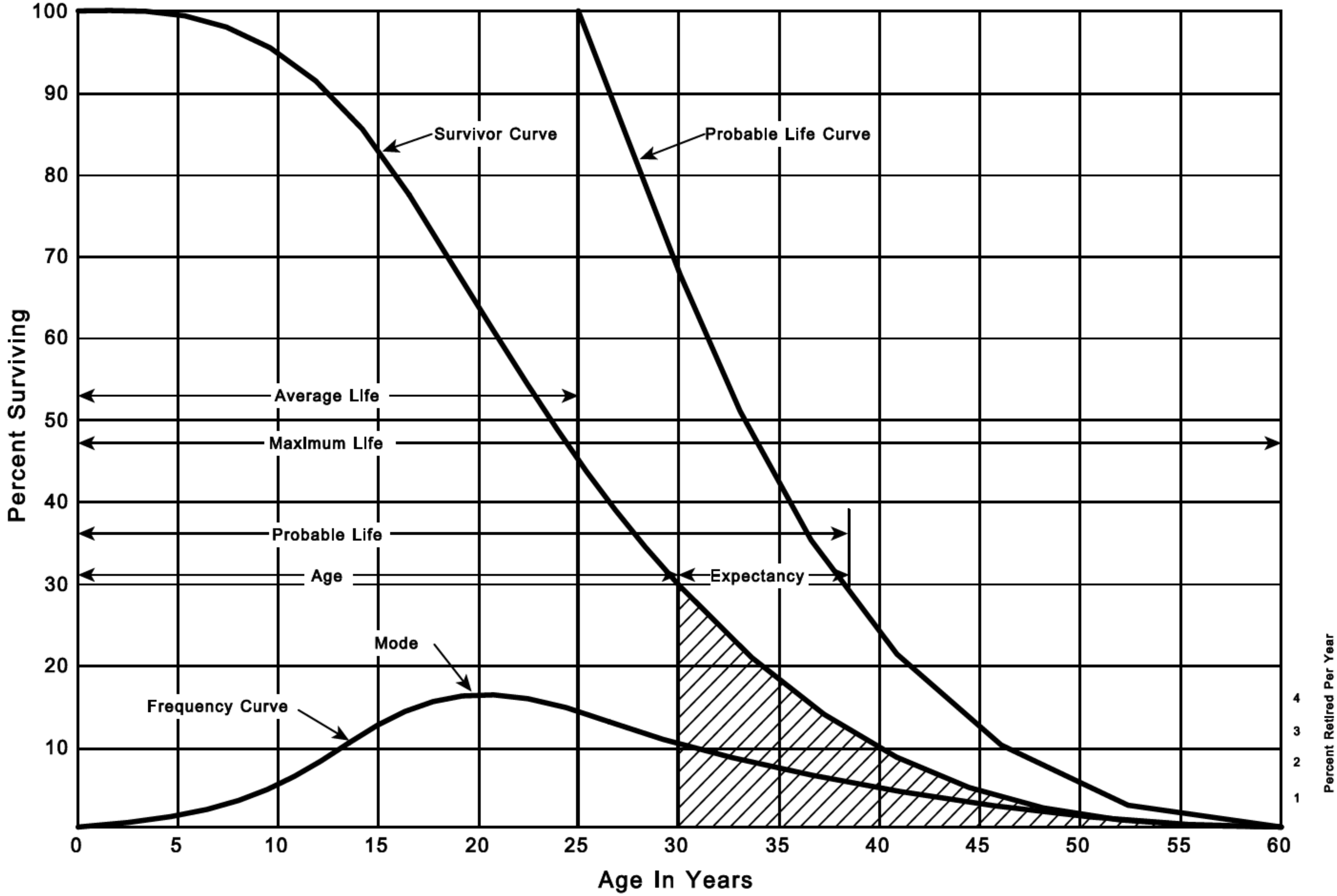



Figure 1. A Typical Survivor Curve and Derived Curves

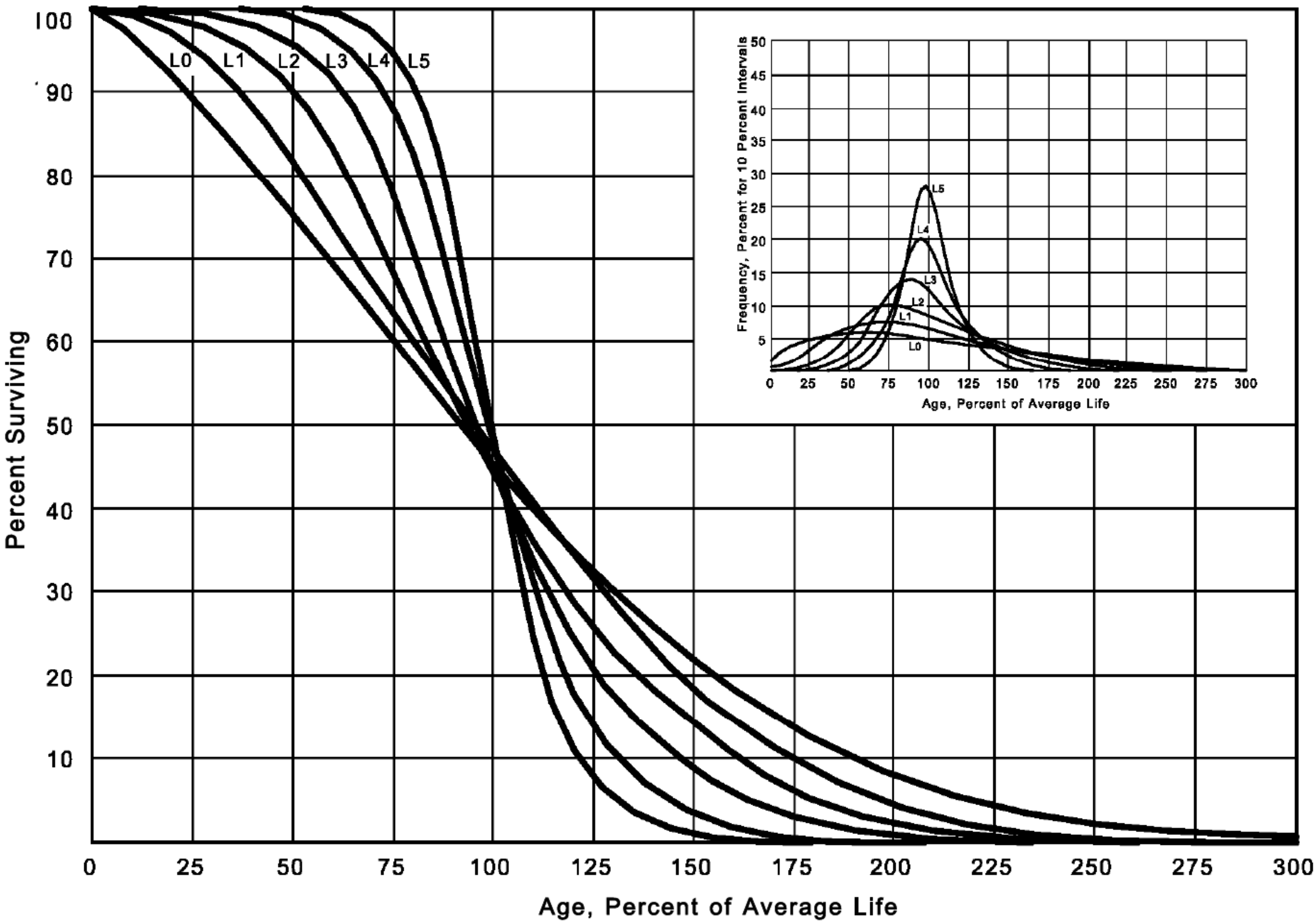



Figure 2. Left Modal or "L" Iowa Type Survivor Curves

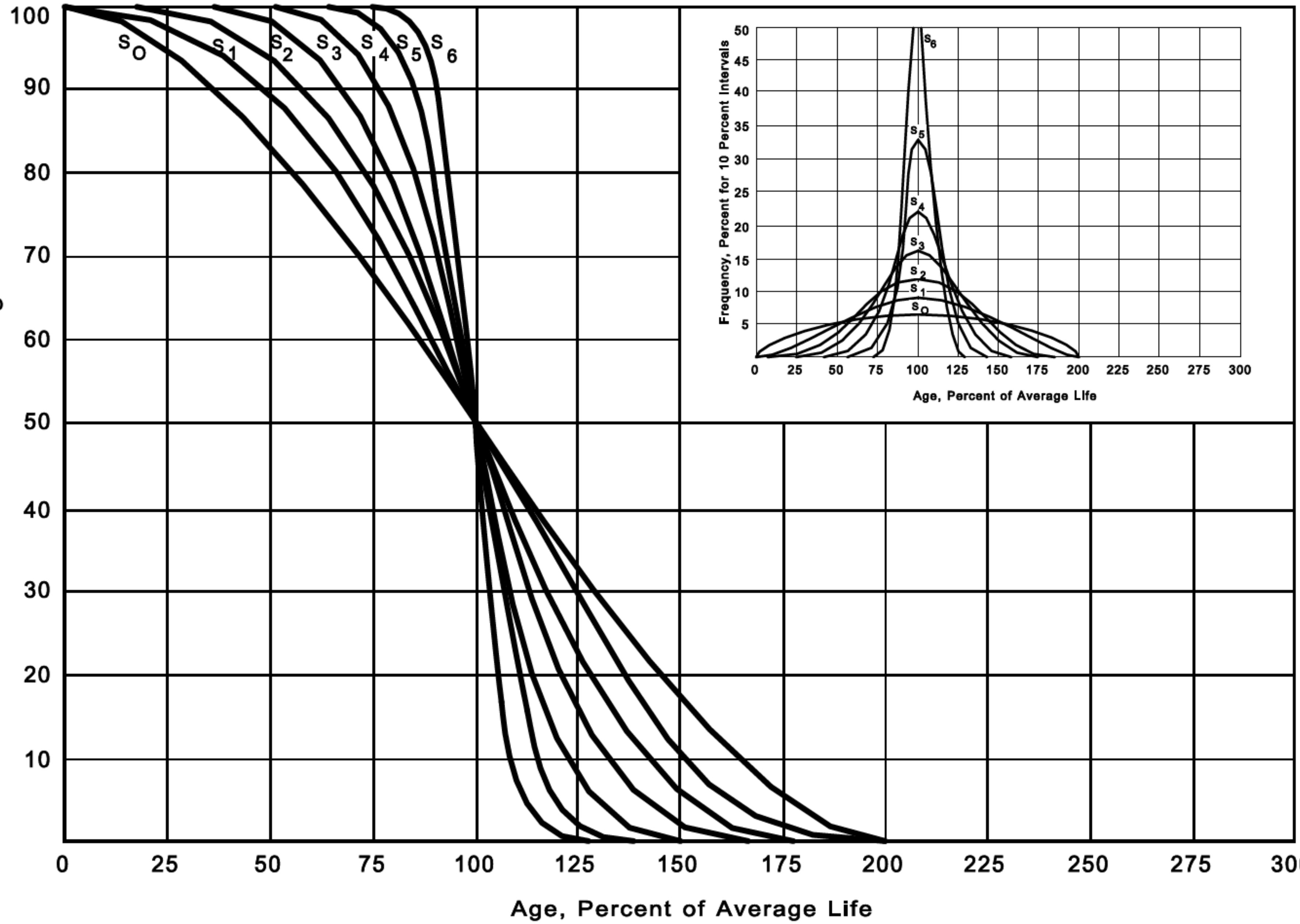



Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

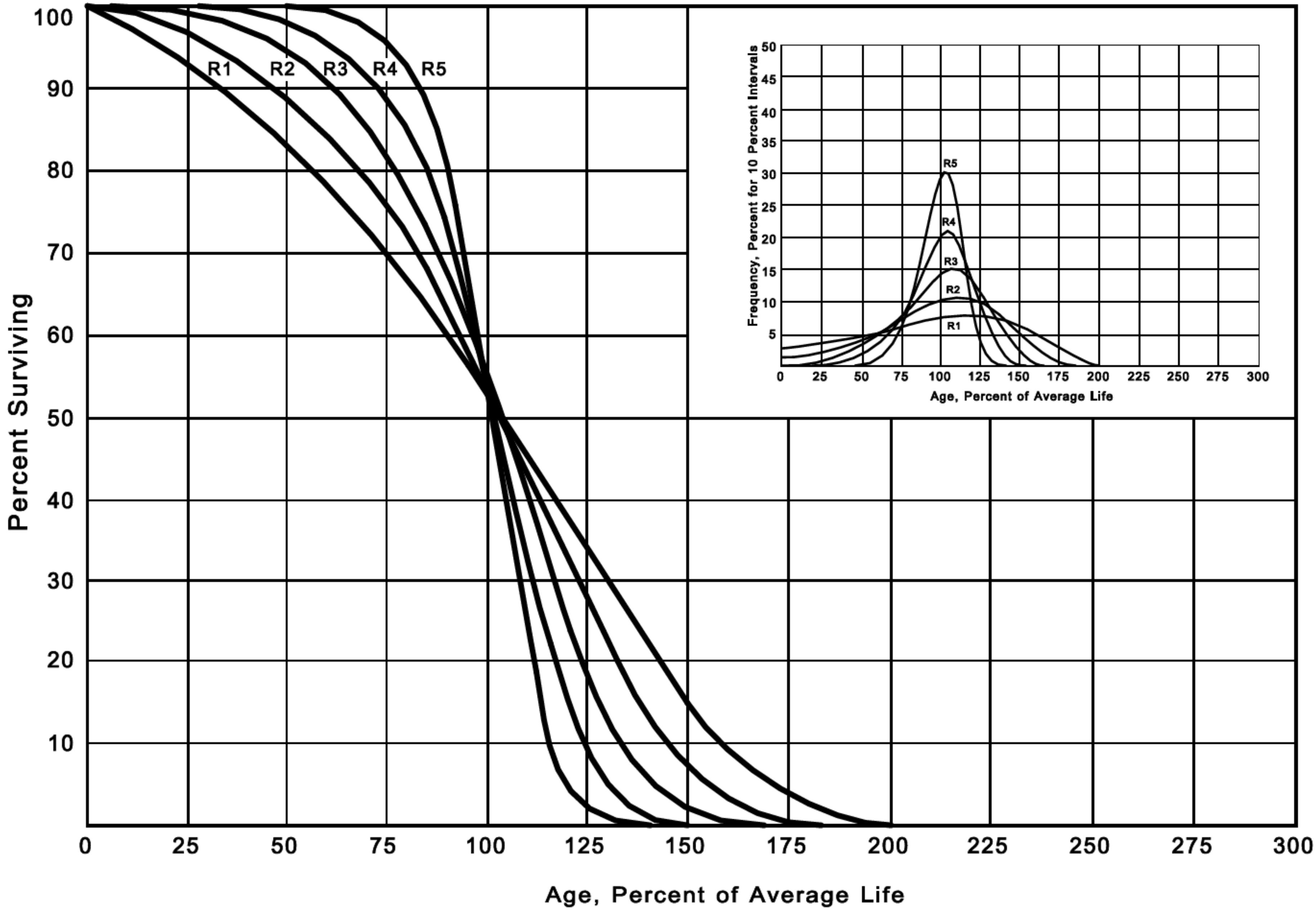



Figure 4. Right Modal or "R" Iowa Type Survivor Curves

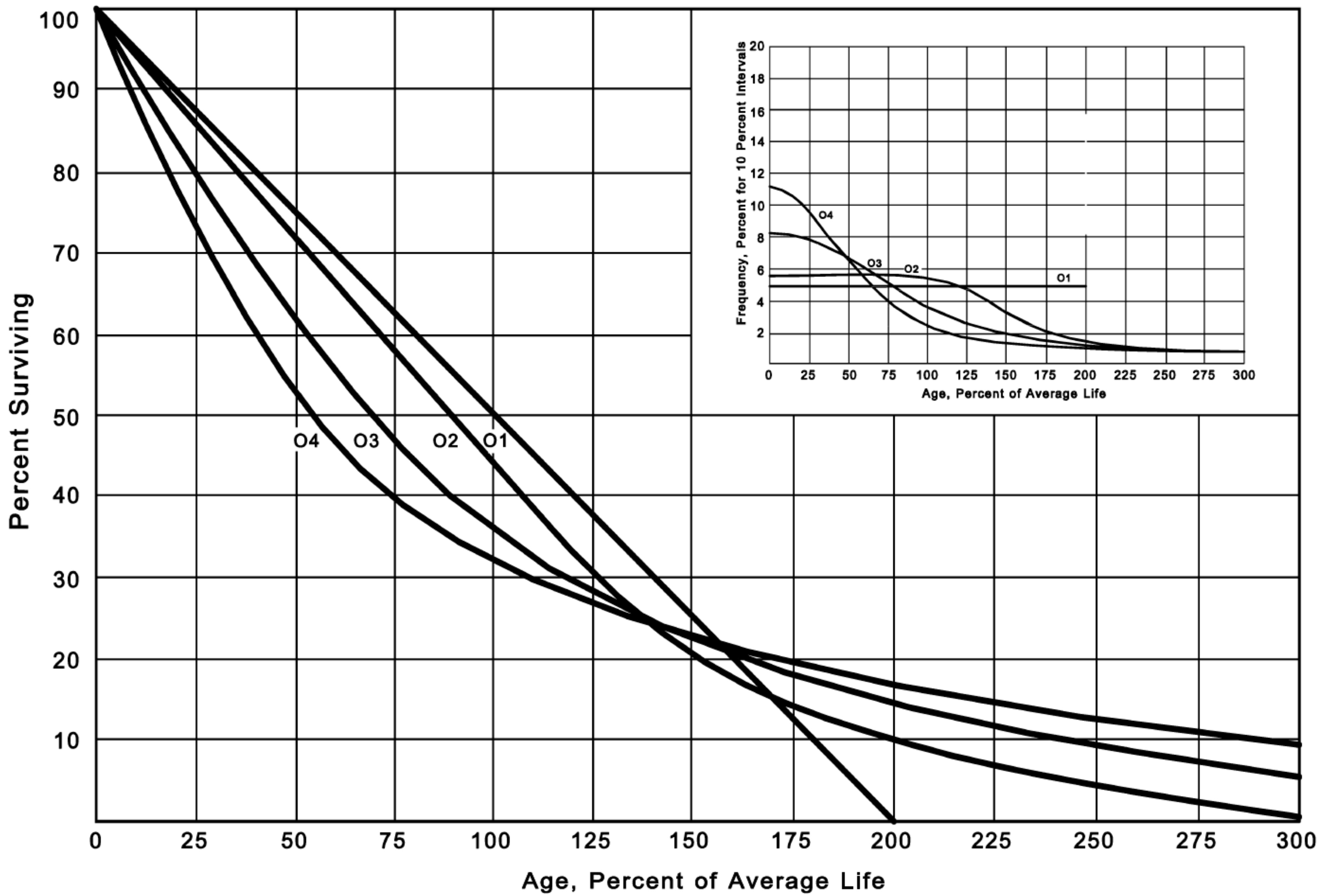



Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

**Retirement Rate Method of Analysis**

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes

---

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College Engineering Experiment Station, Bulletin 125. 1935..

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

**Schedules of Annual Transactions in Plant Records**

The property group used to illustrate the retirement rate method is observed for the experience band 2009-2018 during which there were placements during the years 2004-2018. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2004 were retired in 2009. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2009 retirements of 2004 installations and ending with the 2018 retirements of the 2013 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

I/A

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

| Year Placed | Retirements, Thousands of Dollars During Year 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total During Age Interval | Age Interval |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
| 2004 | 10 | 11 | 12 | 13 | 14 | 16 | 23 | 24 | 25 | 26 | 26 | 13½-14½ |
| 2005 | 11 | 12 | 13 | 15 | 16 | 18 | 20 | 21 | 22 | 19 | 44 | 12½-13½ |
| 2006 | 11 | 12 | 13 | 14 | 16 | 17 | 19 | 21 | 22 | 18 | 64 | 11½-12½ |
| 2007 | 8 | 9 | 10 | 11 | 11 | 13 | 14 | 15 | 16 | 17 | 83 | 10½-11½ |
| 2008 | 9 | 10 | 11 | 12 | 13 | 14 | 16 | 17 | 19 | 20 | 93 | 9½-10½ |
| 2009 | 4 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 20 | 105 | 8½-9½ |
| 2010 | | 5 | 11 | 12 | 13 | 14 | 15 | 16 | 18 | 20 | 113 | 7½-8½ |
| 2011 | | | 6 | 12 | 13 | 15 | 16 | 17 | 19 | 19 | 124 | 6½-7½ |
| 2012 | | | | 6 | 13 | 15 | 16 | 17 | 19 | 19 | 131 | 5½-6½ |
| 2013 | | | | | 7 | 14 | 16 | 17 | 19 | 20 | 143 | 4½-5½ |
| 2014 | | | | | | 8 | 18 | 20 | 22 | 23 | 146 | 3½-4½ |
| 2015 | | | | | | | 9 | 20 | 22 | 25 | 150 | 2½-3½ |
| 2016 | | | | | | | | 11 | 23 | 25 | 151 | 1½-2½ |
| 2017 | | | | | | | | | 11 | 24 | 153 | ½-1½ |
| 2018 | | | | | | | | | | 13 | 80 | 0-½ |
| Total | 53 | 68 | 86 | 106 | 128 | 157 | 196 | 231 | 273 | 308 | 1,606 | |

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

Acquisitions, Transfers and Sales, Thousands of Dollars — During Year

| Year Placed (1) | 2009 (2) | 2010 (3) | 2011 (4) | 2012 (5) | 2013 (6) | 2014 (7) | 2015 (8) | 2016 (9) | 2017 (10) | 2018 (11) | Total During Age Interval (12) | Age Interval (13) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2004 | - | - | - | - | - | - | 60[a] | - | - | - | - | 13½-14½ |
| 2005 | - | - | - | - | - | - | - | - | - | - | - | 12½-13½ |
| 2006 | - | - | - | - | - | - | - | - | - | - | - | 11½-12½ |
| 2007 | - | - | - | - | - | - | - | (5)[b] | - | - | 60 | 10½-11½ |
| 2008 | - | - | - | - | - | - | - | 6[a] | - | - | - | 9½-10½ |
| 2009 | - | - | - | - | - | - | - | - | - | - | (5) | 8½-9½ |
| 2010 | | - | - | - | - | - | - | - | - | - | 6 | 7½-8½ |
| 2011 | | | - | - | - | - | - | - | - | - | - | 6½-7½ |
| 2012 | | | | - | - | - | - | (12)[b] | - | - | - | 5½-6½ |
| 2013 | | | | | - | - | - | - | 22[a] | - | - | 4½-5½ |
| 2014 | | | | | | - | - | (19)[b] | - | - | 10 | 3½-4½ |
| 2015 | | | | | | | - | - | - | - | - | 2½-3½ |
| 2016 | | | | | | | | - | - | (102)[c] | (121) | 1½-2½ |
| 2017 | | | | | | | | | - | - | - | ½-1½ |
| 2018 | | | | | | | | | | | - | 0-½ |
| Total | - | - | - | - | - | - | 60 | (30) | 22 | (102) | (50) | |

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

**Schedule of Plant Exposed to Retirement**

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2009 through 2018 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or additions are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2014 are calculated in the following manner:

| | | |
|---|---|---|
| Exposures at age 0 | = amount of addition | = $750,000 |
| Exposures at age ½ | = $750,000 - $ 8,000 | = $742,000 |
| Exposures at age 1½ | = $742,000 - $18,000 | = $724,000 |
| Exposures at age 2½ | = $724,000 - $20,000 - $19,000 | = $685,000 |
| Exposures at age 3½ | = $685,000 - $22,000 | = $663,000 |

I/A

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2009-2018
SUMMARIZED BY AGE INTERVAL

Experience Band 2009-2018 | Placement Band 2004-2018

| Year Placed | Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | Total at Beginning of Age Interval | Age Interval |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) |
| 2004 | 255 | 245 | 234 | 222 | 209 | 195 | 239 | 216 | 192 | 167 | 167 | 13½-14½ |
| 2005 | 279 | 268 | 256 | 243 | 228 | 212 | 194 | 174 | 153 | 131 | 323 | 12½-13½ |
| 2006 | 307 | 296 | 284 | 271 | 257 | 241 | 224 | 205 | 184 | 162 | 531 | 11½-12½ |
| 2007 | 338 | 330 | 321 | 311 | 300 | 289 | 276 | 262 | 242 | 226 | 823 | 10½-11½ |
| 2008 | 376 | 367 | 357 | 346 | 334 | 321 | 307 | 297 | 280 | 261 | 1,097 | 9½-10½ |
| 2009 | 420[a] | 416 | 407 | 397 | 386 | 374 | 361 | 347 | 332 | 316 | 1,503 | 8½-9½ |
| 2010 | | 460[a] | 455 | 444 | 432 | 419 | 405 | 390 | 374 | 356 | 1,952 | 7½-8½ |
| 2011 | | | 510[a] | 504 | 492 | 479 | 464 | 448 | 431 | 412 | 2,463 | 6½-7½ |
| 2012 | | | | 580[a] | 574 | 561 | 546 | 530 | 501 | 482 | 3,057 | 5½-6½ |
| 2013 | | | | | 660[a] | 653 | 639 | 623 | 628 | 609 | 3,789 | 4½-5½ |
| 2014 | | | | | | 750[a] | 742 | 724 | 685 | 663 | 4,332 | 3½-4½ |
| 2015 | | | | | | | 850[a] | 841 | 821 | 799 | 4,955 | 2½-3½ |
| 2016 | | | | | | | | 960[a] | 949 | 926 | 5,719 | 1½-2½ |
| 2017 | | | | | | | | | 1,080[a] | 1,069 | 6,579 | ½-1½ |
| 2018 | | | | | | | | | | 1,220[a] | 7,490 | 0-½ |
| Total | 1,975 | 2,382 | 2,824 | 3,318 | 3,872 | 4,494 | 5,247 | 6,017 | 6,852 | 7,799 | 44,780 | |

[a]Additions during the year

For the entire experience band 2009-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

**Original Life Table**

The original life table, illustrated in Schedule 4 on page II-16**,** is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

| | | | | |
|---|---|---|---|---|
| Percent surviving at age 4½ | = | 88.15 | | |
| Exposures at age 4½ | = | 3,789,000 | | |
| Retirements from age 4½ to 5½ | = | 143,000 | | |
| Retirement Ratio | = | 143,000 ÷ 3,789,000 | = | 0.0377 |
| Survivor Ratio | = | 1.000 - 0.0377 | = | 0.9623 |
| Percent surviving at age 5½ | = | (88.15) x (0.9623) | = | 84.83 |

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

# SCHEDULE 4. ORIGINAL LIFE TABLE
# CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2009-2018

Placement Band 2004-2018

(Exposure and Retirement Amounts are in Thousands of Dollars)

| Age at Beginning of Interval | Exposures at Beginning of Age Interval | Retirements During Age Interval | Retirement Ratio | Survivor Ratio | Percent Surviving at Beginning of Age Interval |
|---|---|---|---|---|---|
| (1) | (2) | (3) | (4) | (5) | (6) |
| 0.0 | 7,490 | 80 | 0.0107 | 0.9893 | 100.00 |
| 0.5 | 6,579 | 153 | 0.0233 | 0.9767 | 98.93 |
| 1.5 | 5,719 | 151 | 0.0264 | 0.9736 | 96.62 |
| 2.5 | 4,955 | 150 | 0.0303 | 0.9697 | 94.07 |
| 3.5 | 4,332 | 146 | 0.0337 | 0.9663 | 91.22 |
| 4.5 | 3,789 | 143 | 0.0377 | 0.9623 | 88.15 |
| 5.5 | 3,057 | 131 | 0.0429 | 0.9571 | 84.83 |
| 6.5 | 2,463 | 124 | 0.0503 | 0.9497 | 81.19 |
| 7.5 | 1,952 | 113 | 0.0579 | 0.9421 | 77.11 |
| 8.5 | 1,503 | 105 | 0.0699 | 0.9301 | 72.65 |
| 9.5 | 1,097 | 93 | 0.0848 | 0.9152 | 67.57 |
| 10.5 | 823 | 83 | 0.1009 | 0.8991 | 61.84 |
| 11.5 | 531 | 64 | 0.1205 | 0.8795 | 55.60 |
| 12.5 | 323 | 44 | 0.1362 | 0.8638 | 48.90 |
| 13.5 | 167 | 26 | 0.1557 | 0.8443 | 42.24 |
| | | | | | 35.66 |
| Total | 44,780 | 1,606 | | | |

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

**Smoothing the Original Survivor Curve**

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

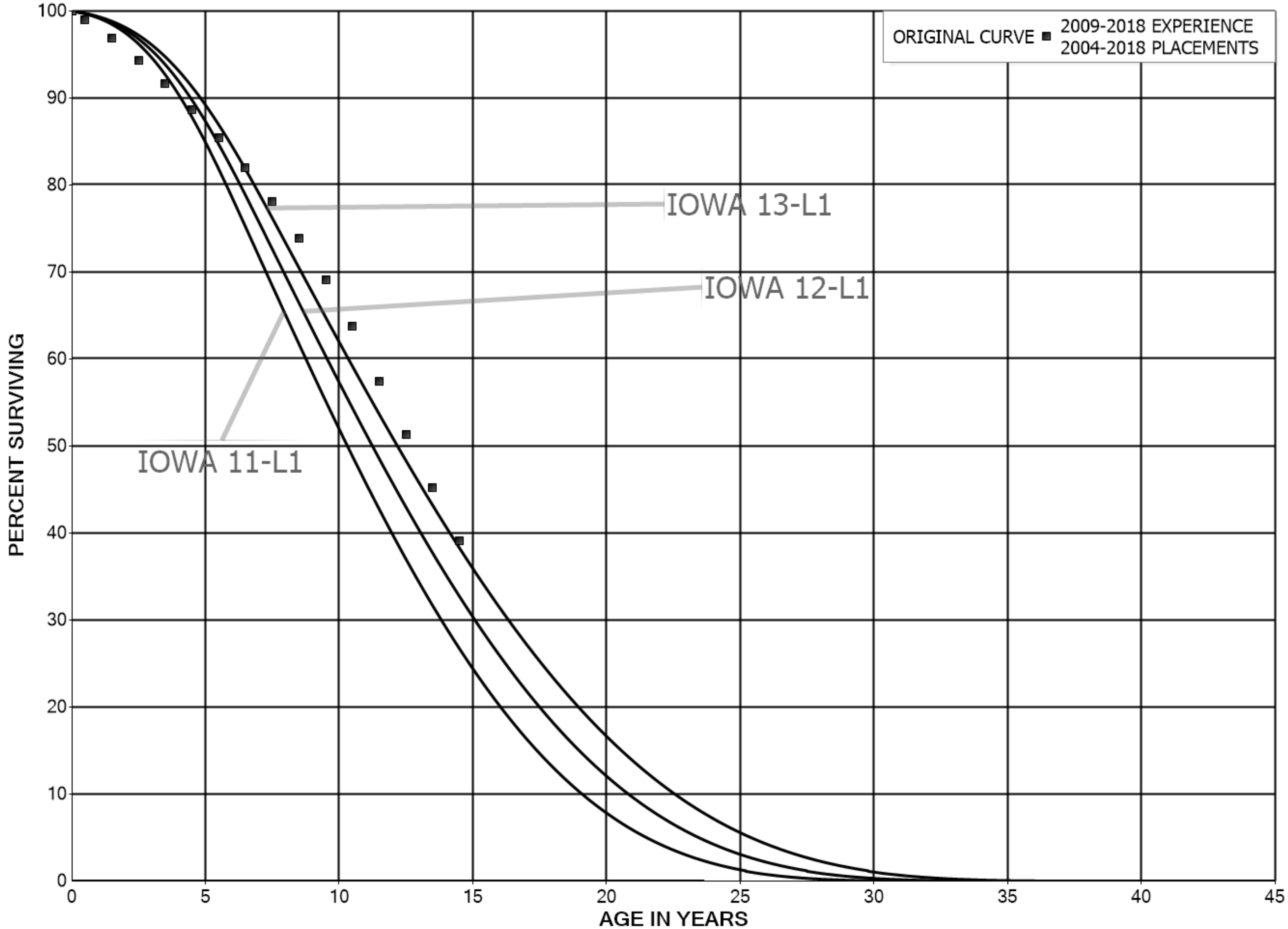


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

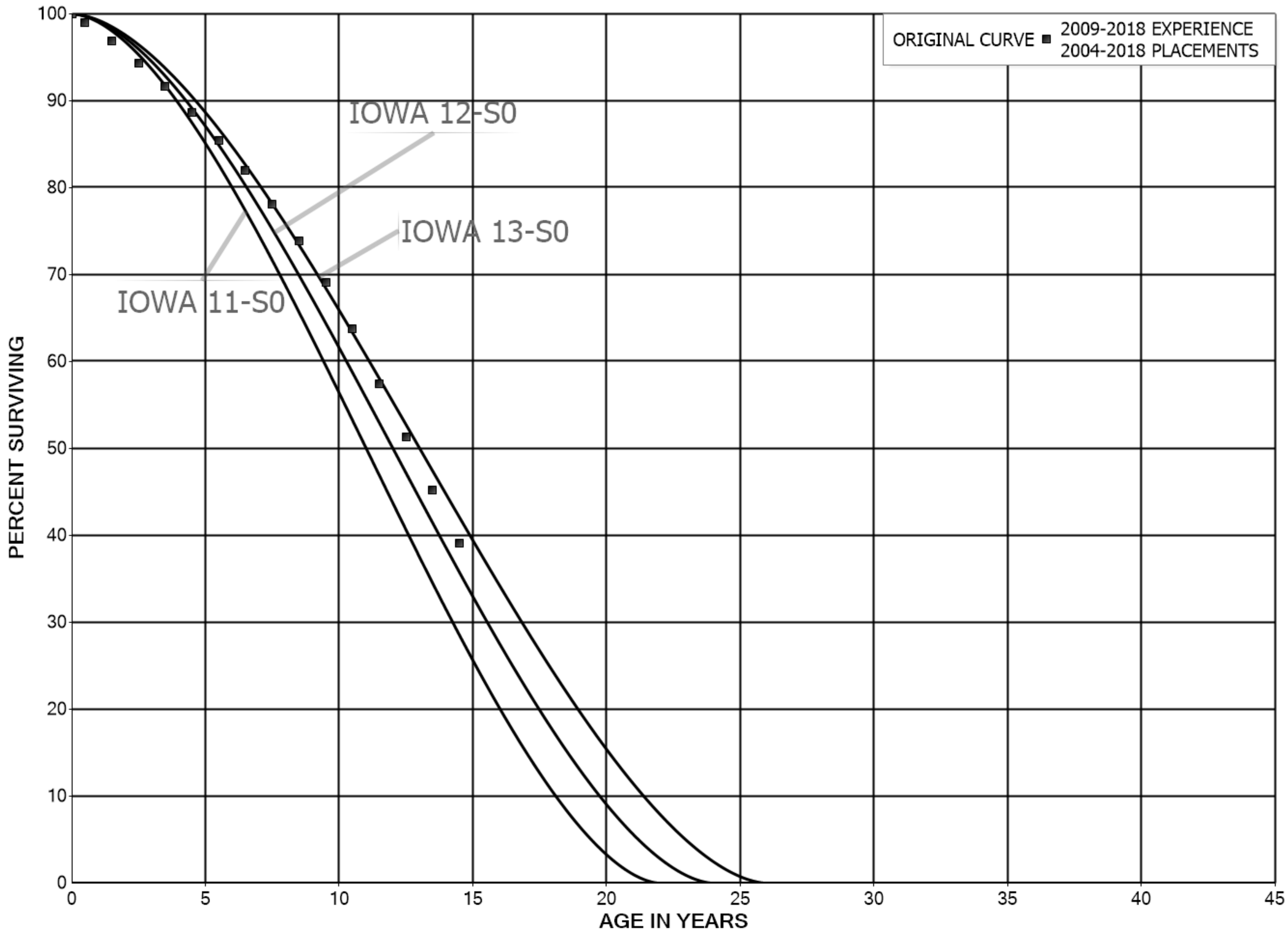
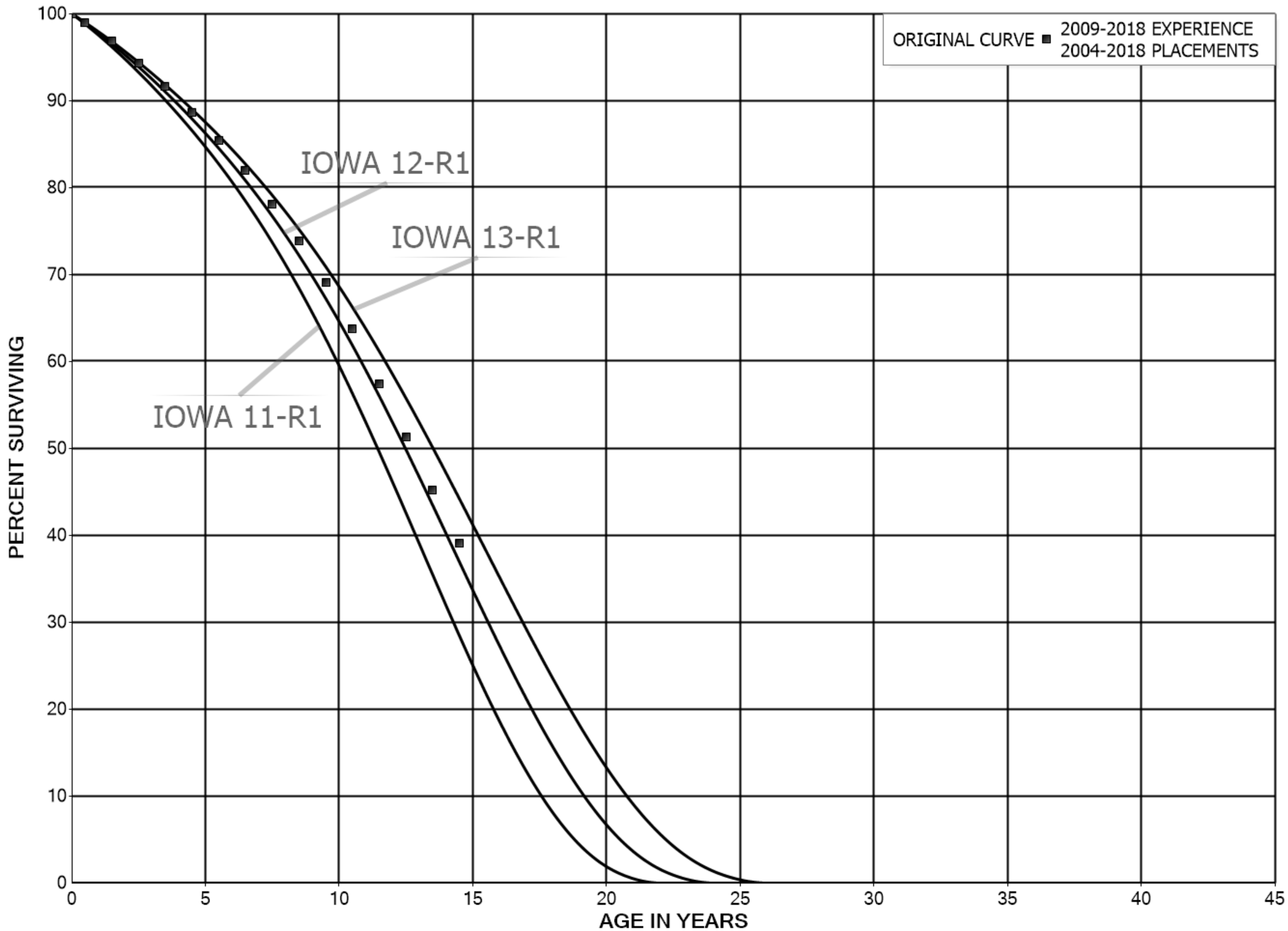
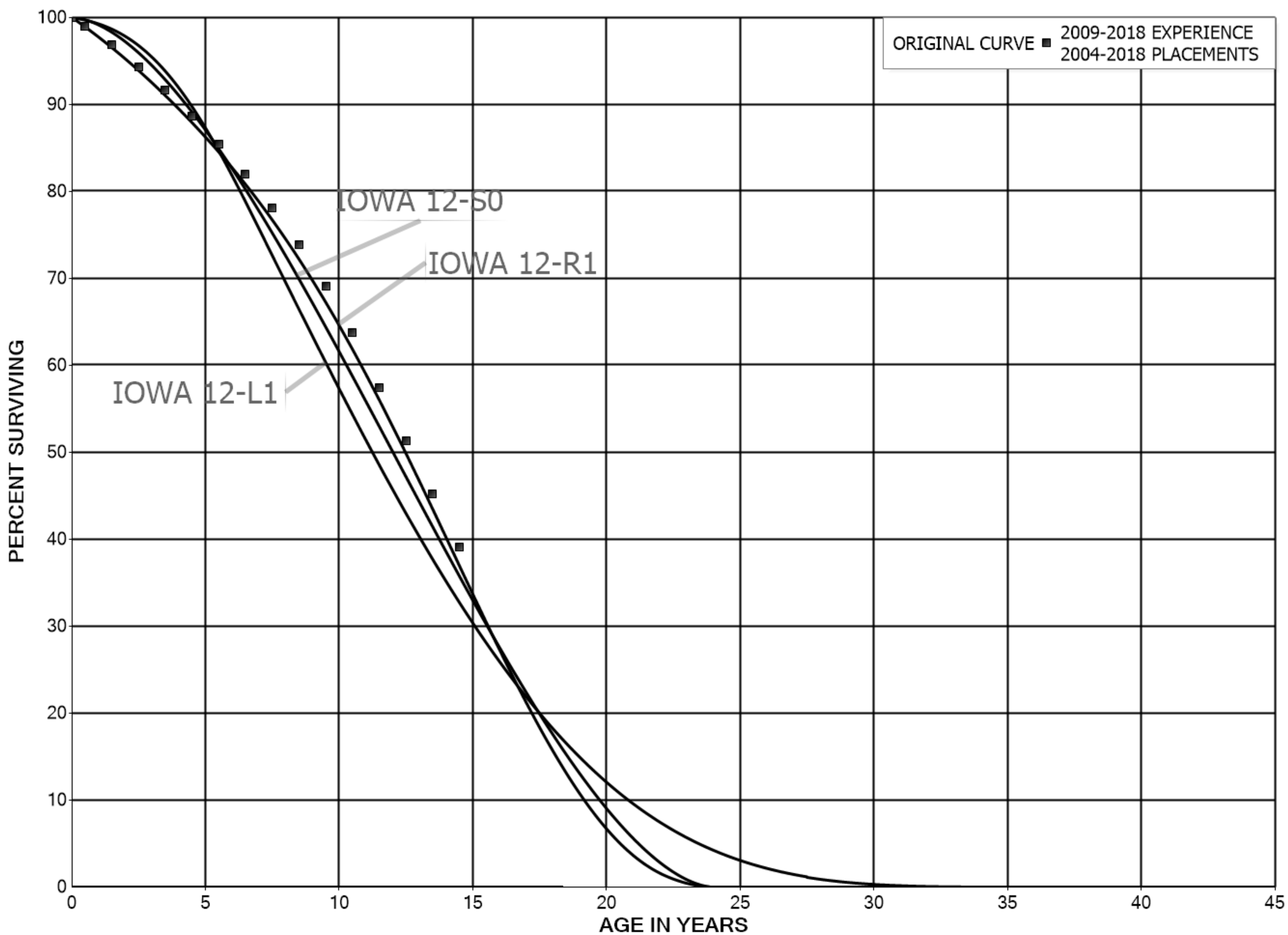


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



Gannett Fleming

FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



# PART III. SERVICE LIFE CONSIDERATIONS

# PART III. SERVICE LIFE CONSIDERATIONS

## FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trips.

June 12-13, 2019
- H.F. Lee Combined Cycle Turbines
- H.F. Lee / Wayne County Combustion Turbine Generators
- H.F. Lee 230 KV Substation
- H.F. Lee 115 KV Substation
- Goldsboro Hemlock Substation
- Goldsboro Weil Substation
- Sutton Generation Facility
- Sutton Blackstart Units
- Darlington Generation Facility

January 13, 2017
- Asheville Generating Station

December 6-7, 2016
- Blewett Generating Station
- Smith Energy Complex
- Roxboro Generating Station
- Mayo Generating Station

## SERVICE LIFE ANALYSIS

The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data, current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric utility companies.

For 35 plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 92 percent of depreciable plant. Generally, the information external to the statistics led to minimal or no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

STEAM PRODUCTION PLANT

| | |
|---|---|
| 311.00 | Structures and Improvements |
| 312.00 | Boiler Plant Equipment |
| 312.10 | Boiler Plant Equipment – SCR Catalyst |
| 314.00 | Turbogenerator Units |
| 315.00 | Accessory Electric Equipment |
| 316.00 | Miscellaneous Power Plant Equipment |

NUCLEAR PRODUCTION PLANT

| | |
|---|---|
| 321.00 | Structures and Improvements |
| 322.00 | Reactor Plant Equipment |
| 323.00 | Turbogenerator Units |
| 324.00 | Accessory Electric Equipment |
| 325.00 | Miscellaneous Power Plant Equipment |

HYDRAULIC PRODUCTION PLANT

| | |
|---|---|
| 331.00 | Structures and Improvements |
| 332.00 | Reservoirs, Dams and Waterway |
| 333.00 | Water Wheels, Turbines and Generators |

OTHER PRODUCTION PLANT

| | |
|---|---|
| 342.00 | Fuel Holders, Producers and Accessories |
| 343.00 | Prime Movers |
| 343.10 | Prime Movers – Rotable Parts |
| 345.00 | Accessory Electric Equipment |
| 346.00 | Miscellaneous Power Plant Equipment |

TRANSMISSION PLANT

| | |
|---|---|
| 353.00 | Station Equipment |
| 354.00 | Towers and Fixtures |

| | |
|---|---|
| 355.00 | Poles and Fixtures |

DISTRIBUTION PLANT

| | |
|---|---|
| 362.00 | Station Equipment |
| 364.00 | Poles, Towers and Fixtures |
| 365.00 | Overhead Conductors and Devices |
| 366.00 | Underground Conduit |
| 367.00 | Underground Conductors and Devices |
| 368.00 | Line Transformers |
| 369.00 | Services |
| 370.00 | Metering Equipment |
| 370.01 | Meters |
| 371.00 | Installations on Customer Premises |
| 373.00 | Street Lighting and Signal Systems |

GENERAL PLANT

| | |
|---|---|
| 390.00 | Structures and Improvements |
| 392.00 | Transportation Equipment |

Account 365.00, Overhead Conductors and Devices, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged plant accounting data for the overhead conductors have been compiled for the years 1954 through 2018. These data have been coded in the course of the Company's normal record keeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the period 1954 through 2018 and 1979 through 2018. The Iowa 45-R1 is a reasonable fit of the original survivor curve. The 45-year average service life is within the typical average service life range of 40 to 55 years for overhead conductor. The 45-year average service life reflects the Company's plans to replace conductor consistently in the future as have been retired in the past. The previous estimate was a 44-R1.5 survivor curve.

For Account 364, Poles, Towers and Fixtures, the survivor curve estimate is the 45-R2.5. The statistical analysis for this account provides a good indication of service life through age 60. The 45-R2.5 estimate is within the industry range and is consistent with the outlook for this account. Based on these considerations, the 45-R2.5 survivor curve is the most reasonable estimate for this account.

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

**Life Span Estimates**

Inasmuch as production plant consists of large generating units, the life span technique was employed in conjunction with the use of interim survivor curves which reflect interim retirements that occur prior to the ultimate retirement of the major unit. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for steam, nuclear, hydraulic and other production plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1923 through 2018 for steam; 1971 through 2018 for nuclear; 1912 through 2018 for hydraulic; and 1968 through 2018 for other production.

The depreciable life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishments, discussions with management personnel concerning the probable long-term outlook for the units, and the estimate of the operating partner, if applicable.

The depreciable life span estimate for most steam, base-load units is 48 to 63 years, which is within the typical range of life spans for such units. With the exception of the Asheville units, these life spans represent the expected depreciable life of each facility under their current configuration. The Company plans to retire the Asheville steam units in 2019. The Company's proposal is to recover the costs of this facility over the remaining 9-year period, which is consistent with the prior study. For the other facilities, future capital expenditures can extend a facility's depreciable life, however, such changes to depreciable life would not be prudent until the capital expenditures are actually put into plant in service. The life span for nuclear units is approximately 60 years, and is consistent with the license dates for each unit. The depreciable life span for hydraulic units is 104 to 143 years which corresponds to the license or relicense dates. A life span of 40-53 years was estimated for the combustion turbines. These life span estimates are typical for combustion turbines which are used primarily as peaking units. The combined cycle units are relatively new units with a commonly used 40-year life span estimate. All solar facilities have recently been constructed and will have a 25-year life span.

A summary of the major year in service, depreciable life span and depreciable life date for each power production unit follows:

| Depreciable Group | Major Year in Service | Depreciable Life Date | Depreciable Life Span |
|---|---|---|---|
| Steam Production Plant | | | |
| Asheville Unit 1 | 1964 | 2027 | 63 |
| Asheville Unit 2 | 1971 | 2027 | 56 |
| Mayo Unit 1 | 1983 | 2029 | 48 |
| Roxboro Unit 1 | 1966 | 2028 | 62 |
| Roxboro Unit 2 | 1968 | 2028 | 60 |
| Roxboro Unit 3 | 1973 | 2029 | 56 |
| Roxboro Unit 4 | 1980 | 2029 | 49 |
| Nuclear Production Plant | | | |
| Brunswick Unit 1 | 1977 | 2036 | 59 |
| Brunswick Unit 2 | 1975 | 2034 | 59 |
| Harris Unit 1 | 1987 | 2046 | 59 |

| Depreciable Group | Major Year in Service | Depreciable Life Date | Depreciable Life Span |
|---|---|---|---|
| Robinson Unit 1 | 1971 | 2030 | 59 |
| | | | |
| Hydraulic Production Plant | | | |
| Blewett | 1912 | 2055 | 143 |
| Marshall | 1910 | 2035 | 125 |
| Tillery | 1928 | 2055 | 127 |
| Walters | 1930 | 2034 | 104 |
| | | | |
| Other Production Plant | | | |
| Asheville | 1999 | 2039 | 40 |
| Blewett | 1971 | 2024 | 53 |
| Darlington Units 1-11 | 1974 | 2020 | 46 |
| Darlington Units 12 and 13 | 1997 | 2037 | 40 |
| H.F. Lee (Wayne County) Units 10-13 | 2000 | 2040 | 40 |
| H.F. Lee (Wayne County) Unit 14 | 2009 | 2049 | 40 |
| Sutton CC | 2013 | 2053 | 40 |
| Sutton Blackstart | 2017 | 2057 | 40 |
| Weatherspoon | 1970 | 2024 | 54 |
| Smith CC (Richmond County) Block 4 | 2002 | 2042 | 40 |
| Smith CC (Richmond County) Block 5 | 2011 | 2051 | 40 |
| Smith CTs | 2001 | 2041 | 40 |
| H.F. Lee CC (Wayne County) | 2012 | 2052 | 40 |
| Camp Lejune Solar | 2015 | 2040 | 25 |
| Fayetteville Solar | 2015 | 2040 | 25 |
| Elm City Solar | 2016 | 2041 | 25 |
| Warsaw Solar | 2015 | 2040 | 25 |

The selected amortization periods for other General Plant accounts are described in the section “Calculated Annual and Accrued Amortization.”

# PART IV. NET SALVAGE CONSIDERATIONS

# PART IV. NET SALVAGE CONSIDERATIONS

## SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled through 2018. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

### Net Salvage Considerations

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and salvage data are presented in the section titled "Net Salvage Statistics" for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the periods 1979 through 2018 for all plant accounts were analyzed. The analyses contributed significantly toward the net salvage estimates for 37 plant accounts, representing 87 percent of the depreciable plant, as follows:

STEAM PRODUCTION PLANT

| | |
|---|---|
| 311.00 | Structures and Improvements |
| 312.00 | Boiler Plant Equipment |
| 312.10 | Boiler Plant Equipment – SCR Catalyst |
| 314.00 | Turbogenerator Units |

| | |
|---|---|
| 315.00 | Accessory Electric Equipment |
| 316.00 | Miscellaneous Power Plant Equipment |

NUCLEAR PRODUCTION PLANT

| | |
|---|---|
| 321.00 | Structures and Improvements |
| 322.00 | Reactor Plant Equipment |
| 323.00 | Turbogenerator Units |
| 324.00 | Accessory Electric Equipment |
| 325.00 | Miscellaneous Power Plant Equipment |

HYDRAULIC PRODUCTION PLANT

| | |
|---|---|
| 332.00 | Reservoirs, Dams and Waterway |
| 334.00 | Accessory Electric Equipment |
| 335.00 | Miscellaneous Power Plant Equipment |

OTHER PRODUCTION PLANT

| | |
|---|---|
| 341.00 | Structures and Improvements |
| 342.00 | Fuel Holders, Producers and Accessories |
| 344.00 | Generators |
| 345.00 | Accessory Electric Equipment |
| 346.00 | Miscellaneous Power Plant Equipment |

TRANSMISSION PLANT

| | |
|---|---|
| 352.00 | Structures and Improvements |
| 353.00 | Station Equipment |
| 355.00 | Poles and Fixtures |

DISTRIBUTION PLANT

| | |
|---|---|
| 361.00 | Structures and Improvements |
| 362.00 | Station Equipment |
| 364.00 | Poles, Towers and Fixtures |
| 365.00 | Overhead Conductors and Devices |
| 366.00 | Underground Conduit |
| 367.00 | Underground Conductors and Devices |
| 368.00 | Line Transformers |
| 369.00 | Services |
| 370.00 | Metering Equipment |
| 370.01 | Meters |
| 371.00 | Installations on Customer Premises |
| 373.00 | Street Lighting and Signal Systems |

GENERAL PLANT

| | |
|---|---|
| 390.00 | Structures and Improvements |
| 392.00 | Transportation Equipment |
| 396.00 | Power Operated Equipment |

Account 368.00, Line Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Net salvage data for the period 1979 through 2018 were analyzed for this account. The data include cost of removal, gross salvage and net salvage amounts and each of these amounts is expressed as a percent of the original cost of regular retirements. Three-year moving averages for the 1979-1981 through 2016-2018 periods were computed to smooth the annual amounts.

Cost of removal was relatively consistent during the 1980s and 1990s, then fluctuated over the last 20 years. The primary cause of the high levels of cost of removal in recent years was the required effort needed to replace transformers due to various forces of retirement. Cost of removal for the most recent five years averaged 13 percent.

Gross salvage has varied throughout the period with high levels in 2011 and 2013 due to current practices of reuse. The most recent five-year average of 5 percent gross salvage reflects recent trends.

The net salvage percent based on the overall period 1979 through 2018 is 0 percent net salvage and based on the most recent five-year period is negative 7 percent. The typical range of estimates made by other electric companies for Line Transformers is positive 5 to negative 15 percent. The net salvage estimate for line transformers is negative 5 percent, is within the range of other estimates and reflects the levels of net salvage experienced over the last ten years.

The net salvage estimate for Account 353, Station Equipment, is negative 15 percent. Net salvage data for the period 1979 through 2018 were analyzed for this account. Cost of removal has been high in most years for the period studied. There has been some gross salvage, but it has been less than cost of removal and has only averaged 2 percent since 2000 with the exception to 2006. For the period 1979 through 2018, net salvage has averaged negative 9 percent. More recent years have experienced higher levels of retirements and have also experienced increased costs of removal. The most recent five year average is negative 17 percent.

Estimates of negative 20 percent or less are common in the industry for this account, although there has been a trend to more negative net salvage in this account in recent years and some utilities do have estimates that are even more negative. While the trend for this account does support a slightly more negative net salvage estimate than negative 15 percent, the negative 15 percent estimate reflects the expectations of the Company for this account as well as the experience of others in the industry.

The overall net salvage estimates for the Company's production facilities, for which the life span method is used, is based on estimates of both final net salvage and interim net salvage. Final net salvage is the net salvage experienced at the end of a production plant's life span. Interim net salvage is the net salvage experienced for interim retirements that occur prior to the final retirement of the plant. The final net salvage estimates in the study were based on a decommissioning study performed by Burns & McDonnell. These studies excluded ash pond closure activities. The interim net salvage estimates were based in part on an analysis of historical interim retirement and net salvage data. Based on informed judgment that incorporated these interim net salvage analyses for each plant account, an interim net salvage estimate of negative 15 percent was used for steam plant accounts; negative 7 percent for nuclear plant accounts; negative 18 percent for hydraulic plant accounts; and a negative 4 percent estimate was used for other production plant account and 0 percent for solar assets. The one exception is for Account 343.10, Prime Movers – Rotable Parts units for the combined cycle units. This account includes the hot gas path components of the combustion turbines for these plants. An interim net salvage estimate of 40 percent is recommended, consistent with the historical data and outlook for these assets.

The interim survivor curve estimates for each account and production facility were used to calculate the percentage of plant expected to be retired as interim retirements and final retirements. These are shown on Table 1 in the Net Salvage Statistics section on page VIII-2. These percentages were used to determine the weighted net salvage estimate for each account and production facility based on the interim and final net salvage estimates. These calculations, as well as the estimated final net salvage and interim net salvage percents, are shown on Table 2 of the Net Salvage Statistics section on page VIII-3. Table 3 sets forth the calculation for establishing the terminal net salvage percent for each location which is utilized in Table 2.

The net salvage percents for the remaining accounts were based on judgment incorporating factors such as the statistical net salvage analysis, general knowledge of the property studied, and estimates of previous studies of this and other electric utilities.

Generally, the net salvage estimates for remaining general plant accounts were zero percent, consistent with amortization accounting.

# PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

# PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

## GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

**<u>Single Unit of Property</u>**

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4\ +\ 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000\left(1\ -\ \frac{6}{10}\right) = \$400.$$

## Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2018, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2018, are set forth in the Results of Study section of the report.

## Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

## CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of total depreciable electric plant in service. The accounts and their amortization periods are as follows:

| | Account | Amortization Period, Years |
|---|---|---|
| 391, | Office Furniture and Equipment | |
| | Furniture and Equipment | 15 |
| | EDP | 8 |
| 393, | Stores Equipment | 20 |
| 394, | Tools, Shop and Garage Equipment | 20 |
| 395, | Laboratory Equipment | 15 |
| 397, | Communication Equipment | 10 |
| 398, | Miscellaneous Equipment | 20 |

For the purpose of calculating annual amortization amounts as of December 31, 2018, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

# PART VI. RESULTS OF STUDY

# PART VI. RESULTS OF STUDY

## QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2018. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2018, is reasonable for a period of three to five years.

## DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of salvage data are presented in the section titled, "Net Salvage Statistics". The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

## DESCRIPTION OF DEPRECIATION TABULATIONS

A summary of the results of the study, as applied to the original cost of electric plant as of December 31, 2018, is presented on pages VI-4 through VI-11 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life and the calculated annual accrual amount.

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT (1) | PROBABLE RETIREMENT DATE (2) | SURVIVOR CURVE (3) | NET SALVAGE PERCENT (4) | ORIGINAL COST AS OF DECEMBER 31, 2018 (5) | BOOK RESERVE (6) | FUTURE ACCRUALS (7) | CALCULATED ANNUAL ACCRUAL AMOUNT (8) | CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5) | COMPOSITE REMAINING LIFE (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| | **STEAM PRODUCTION PLANT** | | | | | | | | | |
| 311.00 | STRUCTURES AND IMPROVEMENTS | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 100-R2.5 * | (4) | 42,616,358.21 | 39,177,778 | 5,143,234 | 573,609 | 1.35 | 9.0 |
| | ASHEVILLE UNIT 2 | 12-2027 | 100-R2.5 * | (4) | 42,579,071.25 | 31,072,574 | 13,209,660 | 1,473,445 | 3.46 | 9.0 |
| | MAYO UNIT 1 | 06-2029 | 100-R2.5 * | (4) | 170,239,859.39 | 126,127,393 | 50,922,061 | 4,879,145 | 2.87 | 10.4 |
| | ROXBORO UNIT 1 | 06-2028 | 100-R2.5 * | (5) | 17,139,904.05 | 14,127,970 | 3,868,930 | 408,845 | 2.39 | 9.5 |
| | ROXBORO UNIT 2 | 06-2028 | 100-R2.5 * | (5) | 5,512,432.01 | 3,928,468 | 1,859,586 | 196,628 | 3.57 | 9.5 |
| | ROXBORO UNIT 3 | 06-2029 | 100-R2.5 * | (5) | 37,367,402.39 | 35,337,975 | 3,897,798 | 372,911 | 1.00 | 10.5 |
| | ROXBORO UNIT 4 | 06-2029 | 100-R2.5 * | (5) | 19,539,071.49 | 9,595,015 | 10,921,010 | 1,048,303 | 5.37 | 10.4 |
| | ROXBORO COMMON | 06-2029 | 100-R2.5 * | (5) | 193,990,592.95 | 49,894,500 | 153,795,623 | 14,718,151 | 7.59 | 10.4 |
| | TOTAL STRUCTURES AND IMPROVEMENTS | | | | 528,984,691.74 | 309,261,673 | 243,617,902 | 23,671,037 | 4.47 | 10.3 |
| 312.00 | BOILER PLANT EQUIPMENT | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 60-R1 * | (4) | 149,655,719.36 | 93,325,565 | 62,316,384 | 7,121,696 | 4.76 | 8.8 |
| | ASHEVILLE UNIT 2 | 12-2027 | 60-R1 * | (4) | 145,625,344.87 | 110,436,602 | 41,013,757 | 4,682,918 | 3.22 | 8.8 |
| | MAYO UNIT 1 | 06-2029 | 60-R1 * | (4) | 832,479,002.87 | 354,948,282 | 510,829,881 | 50,461,597 | 6.06 | 10.1 |
| | ROXBORO UNIT 1 | 06-2028 | 60-R1 * | (5) | 212,902,505.83 | 87,482,059 | 136,065,572 | 14,793,592 | 6.95 | 9.2 |
| | ROXBORO UNIT 2 | 06-2028 | 60-R1 * | (5) | 309,506,429.33 | 168,229,667 | 156,752,084 | 17,017,838 | 5.50 | 9.2 |
| | ROXBORO UNIT 3 | 06-2029 | 60-R1 * | (5) | 333,830,832.31 | 118,836,753 | 231,685,621 | 22,920,294 | 6.87 | 10.1 |
| | ROXBORO UNIT 4 | 06-2029 | 60-R1 * | (5) | 404,141,708.49 | 275,790,947 | 148,557,847 | 14,572,511 | 3.61 | 10.2 |
| | ROXBORO COMMON | 06-2029 | 60-R1 * | (5) | 320,174,907.77 | 168,313,679 | 167,869,974 | 16,435,758 | 5.13 | 10.2 |
| | TOTAL BOILER PLANT EQUIPMENT | | | | 2,708,316,450.83 | 1,377,363,553 | 1,455,091,120 | 148,006,204 | 5.46 | 9.8 |
| 312.10 | BOILER PLANT EQUIPMENT - SCR CATALYST | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 10-S1 * | 0 | 3,957,262.78 | 4,500,630 | (543,367) | 0 | - | - |
| | ASHEVILLE UNIT 2 | 12-2027 | 10-S1 * | 0 | 1,798,265.75 | 1,961,047 | (162,782) | 0 | - | - |
| | MAYO UNIT 1 | 06-2029 | 10-S1 * | 0 | 7,428,602.62 | 7,594,648 | (166,045) | 0 | - | - |
| | ROXBORO UNIT 1 | 06-2028 | 10-S1 * | 0 | 7,925,144.00 | 8,427,153 | (502,009) | 0 | - | - |
| | ROXBORO UNIT 2 | 06-2028 | 10-S1 * | 0 | 5,857,261.54 | 6,103,037 | (245,775) | 0 | - | - |
| | ROXBORO UNIT 3 | 06-2029 | 10-S1 * | 0 | 6,541,925.15 | 4,994,846 | 1,547,079 | 245,298 | 3.75 | 6.3 |
| | ROXBORO UNIT 4 | 06-2029 | 10-S1 * | 0 | 7,261,916.42 | 8,154,038 | (892,122) | 0 | - | - |
| | TOTAL BOILER PLANT EQUIPMENT - SCR CATALYST | | | | 40,770,378.26 | 41,735,399 | (965,021) | 245,298 | 0.60 | (3.9) |
| 314.00 | TURBOGENERATOR UNITS | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 60-S0 * | (4) | 18,830,227.72 | 7,586,897 | 11,996,540 | 1,378,245 | 7.32 | 8.7 |
| | ASHEVILLE UNIT 2 | 12-2027 | 60-S0 * | (4) | 13,968,640.50 | 13,145,255 | 1,382,131 | 155,826 | 1.12 | 8.9 |
| | MAYO UNIT 1 | 06-2029 | 60-S0 * | (4) | 109,608,959.00 | 65,409,412 | 48,583,905 | 4,863,907 | 4.44 | 10.0 |
| | ROXBORO UNIT 1 | 06-2028 | 60-S0 * | (5) | 45,628,567.76 | 18,857,340 | 29,052,656 | 3,153,178 | 6.91 | 9.2 |
| | ROXBORO UNIT 2 | 06-2028 | 60-S0 * | (5) | 44,959,643.18 | 15,793,614 | 31,414,011 | 3,418,913 | 7.60 | 9.2 |
| | ROXBORO UNIT 3 | 06-2029 | 60-S0 * | (5) | 73,030,422.44 | 30,051,305 | 46,630,638 | 4,601,862 | 6.30 | 10.1 |
| | ROXBORO UNIT 4 | 06-2029 | 60-S0 * | (5) | 69,565,691.07 | 35,567,696 | 37,476,280 | 3,723,176 | 5.35 | 10.1 |
| | ROXBORO COMMON | 06-2029 | 60-S0 * | (5) | 458,890.76 | 337,291 | 144,545 | 14,425 | 3.14 | 10.0 |
| | TOTAL TURBOGENERATOR UNITS | | | | 376,051,042.43 | 186,748,811 | 206,680,706 | 21,309,532 | 5.67 | 9.7 |
| 315.00 | ACCESSORY ELECTRIC EQUIPMENT | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 70-R1 * | (4) | 17,304,563.70 | 10,105,982 | 7,890,765 | 896,804 | 5.18 | 8.8 |
| | ASHEVILLE UNIT 2 | 12-2027 | 70-R1 * | (4) | 10,774,312.04 | 11,377,112 | (171,827) | 0 | - | - |
| | MAYO UNIT 1 | 06-2029 | 70-R1 * | (4) | 66,829,604.18 | 32,728,460 | 36,774,329 | 3,607,025 | 5.40 | 10.2 |
| | ROXBORO UNIT 1 | 06-2028 | 70-R1 * | (5) | 27,911,638.64 | 9,388,873 | 19,918,347 | 2,151,100 | 7.71 | 9.3 |
| | ROXBORO UNIT 2 | 06-2028 | 70-R1 * | (5) | 24,223,049.38 | 17,239,203 | 8,194,999 | 883,710 | 3.65 | 9.3 |
| | ROXBORO UNIT 3 | 06-2029 | 70-R1 * | (5) | 42,579,385.55 | 15,020,156 | 29,688,199 | 2,913,552 | 6.84 | 10.2 |
| | ROXBORO UNIT 4 | 06-2029 | 70-R1 * | (5) | 43,547,824.88 | 20,360,939 | 25,364,277 | 2,486,371 | 5.71 | 10.2 |
| | ROXBORO COMMON | 06-2029 | 70-R1 * | (5) | 23,722,266.18 | 7,276,792 | 17,631,587 | 1,723,633 | 7.27 | 10.2 |
| | TOTAL ACCESSORY ELECTRIC EQUIPMENT | | | | 256,892,644.55 | 123,497,516 | 145,290,676 | 14,662,195 | 5.71 | 9.9 |
| 316.00 | MISCELLANEOUS POWER PLANT EQUIPMENT | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 45-S0 * | (4) | 10,334,480.63 | 4,727,909 | 6,019,951 | 695,241 | 6.73 | 8.7 |
| | ASHEVILLE UNIT 2 | 12-2027 | 45-S0 * | (4) | 5,120,201.92 | 4,538,194 | 786,816 | 91,397 | 1.79 | 8.6 |
| | MAYO UNIT 1 | 06-2029 | 45-S0 * | (4) | 13,338,741.21 | 5,584,869 | 8,287,422 | 840,910 | 6.30 | 9.9 |
| | ROXBORO UNIT 1 | 06-2028 | 45-S0 * | (5) | 4,072,524.77 | 1,719,045 | 2,557,106 | 281,244 | 6.91 | 9.1 |
| | ROXBORO UNIT 2 | 06-2028 | 45-S0 * | (5) | 4,425,440.03 | 2,695,586 | 1,951,126 | 214,299 | 4.84 | 9.1 |
| | ROXBORO UNIT 3 | 06-2029 | 45-S0 * | (5) | 4,581,632.45 | 2,143,896 | 2,666,819 | 270,285 | 5.90 | 9.9 |
| | ROXBORO UNIT 4 | 06-2029 | 45-S0 * | (5) | 5,430,383.41 | 2,700,578 | 3,001,325 | 308,691 | 5.68 | 9.7 |
| | ROXBORO COMMON | 06-2029 | 45-S0 * | (5) | 20,631,298.87 | 5,918,365 | 15,744,498 | 1,574,562 | 7.63 | 10.0 |
| | TOTAL MISCELLANEOUS POWER PLANT EQUIPMENT | | | | 67,934,703.29 | 30,028,440 | 41,015,063 | 4,276,629 | 6.30 | 9.6 |
| | **TOTAL STEAM PRODUCTION PLANT** | | | | **3,978,949,911.10** | **2,068,635,392** | **2,090,730,446** | **212,170,895** | **5.33** | **9.9** |

I/A

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT (1) | PROBABLE RETIREMENT DATE (2) | SURVIVOR CURVE (3) | | NET SALVAGE PERCENT (4) | ORIGINAL COST AS OF DECEMBER 31, 2018 (5) | BOOK RESERVE (6) | FUTURE ACCRUALS (7) | CALCULATED ANNUAL ACCRUAL AMOUNT (8) | CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5) | COMPOSITE REMAINING LIFE (10) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **NUCLEAR PRODUCTION PLANT** | | | | | | | | | | |
| 321.00 | STRUCTURES AND IMPROVEMENTS | | | | | | | | | | |
| | BRUNSWICK UNIT 1 | 09-2036 | 75-S1 | * | (1) | 423,009,418.66 | 182,352,007 | 244,887,506 | 14,175,485 | 3.35 | 17.3 |
| | BRUNSWICK UNIT 2 | 12-2034 | 75-S1 | * | (1) | 397,968,469.79 | 223,090,544 | 178,857,611 | 11,520,013 | 2.89 | 15.5 |
| | HARRIS UNIT 1 | 10-2046 | 75-S1 | * | (2) | 1,996,266,873.69 | 1,204,989,357 | 831,202,855 | 32,248,496 | 1.62 | 25.8 |
| | HARRIS DISALLOWANCE | 10-2046 | | | | (105,862,561.00) | (67,742,934) | (38,119,627) | (1,369,567) | 1.29 | 27.8 |
| | ROBINSON UNIT 2 | 07-2030 | 75-S1 | * | (1) | 373,649,660.90 | 190,668,370 | 186,717,788 | 16,338,445 | 4.37 | 11.4 |
| | TOTAL STRUCTURES AND IMPROVEMENTS | | | | | 3,085,031,862.04 | 1,733,357,343 | 1,403,546,133 | 72,912,872 | 2.36 | 19.2 |
| 322.00 | REACTOR PLANT EQUIPMENT | | | | | | | | | | |
| | BRUNSWICK UNIT 1 | 09-2036 | 52-R2 | * | (1) | 612,117,283.68 | 299,468,246 | 318,770,211 | 19,312,794 | 3.16 | 16.5 |
| | BRUNSWICK UNIT 2 | 12-2034 | 52-R2 | * | (1) | 544,476,825.16 | 293,189,240 | 256,732,353 | 17,115,022 | 3.14 | 15.0 |
| | HARRIS UNIT 1 | 10-2046 | 52-R2 | * | (2) | 1,075,559,612.15 | 425,966,772 | 671,104,032 | 28,850,918 | 2.68 | 23.3 |
| | HARRIS DISALLOWANCE | 10-2046 | | | | (132,409,445.00) | (84,730,657) | (47,678,788) | (1,713,010) | 1.29 | 27.8 |
| | ROBINSON UNIT 2 | 07-2030 | 52-R2 | * | (1) | 462,756,240.49 | 249,630,881 | 217,752,922 | 19,464,027 | 4.21 | 11.2 |
| | TOTAL REACTOR PLANT EQUIPMENT | | | | | 2,562,500,516.48 | 1,183,524,482 | 1,416,680,730 | 83,029,751 | 3.24 | 17.1 |
| 323.00 | TURBOGENERATOR UNITS | | | | | | | | | | |
| | BRUNSWICK UNIT 1 | 09-2036 | 40-S0 | * | (1) | 285,997,062.33 | 101,762,273 | 187,094,760 | 11,823,008 | 4.13 | 15.8 |
| | BRUNSWICK UNIT 2 | 12-2034 | 40-S0 | * | (1) | 172,548,284.27 | 83,648,310 | 90,625,457 | 6,442,418 | 3.73 | 14.1 |
| | HARRIS UNIT 1 | 10-2046 | 40-S0 | * | (2) | 535,687,360.49 | 148,284,568 | 398,116,540 | 17,371,808 | 3.24 | 22.9 |
| | HARRIS DISALLOWANCE | 10-2046 | | | | (610,466.00) | (390,646) | (219,820) | (7,898) | 1.29 | 27.8 |
| | ROBINSON UNIT 2 | 07-2030 | 40-S0 | * | (1) | 333,276,803.83 | 41,912,529 | 294,697,043 | 26,899,155 | 8.07 | 11.0 |
| | TOTAL TURBOGENERATOR UNITS | | | | | 1,326,899,044.92 | 375,217,034 | 970,313,980 | 62,528,491 | 4.71 | 15.5 |
| 324.00 | ACCESSORY ELECTRIC EQUIPMENT | | | | | | | | | | |
| | BRUNSWICK UNIT 1 | 09-2036 | 50-R2.5 | * | (1) | 161,647,774.74 | 48,960,985 | 114,303,267 | 6,821,086 | 4.22 | 16.8 |
| | BRUNSWICK UNIT 2 | 12-2034 | 50-R2.5 | * | (1) | 210,342,927.28 | 83,854,412 | 128,591,944 | 8,431,189 | 4.01 | 15.3 |
| | HARRIS UNIT 1 | 10-2046 | 50-R2.5 | * | (2) | 820,436,969.84 | 447,858,632 | 388,987,077 | 16,303,928 | 1.99 | 23.9 |
| | HARRIS DISALLOWANCE | 10-2046 | | | | (256,837,664.66) | (164,354,016) | (92,483,649) | (3,322,766) | 1.29 | 27.8 |
| | ROBINSON UNIT 2 | 07-2030 | 50-R2.5 | * | (1) | 279,070,966.07 | 77,699,673 | 204,162,003 | 17,942,656 | 6.43 | 11.4 |
| | TOTAL ACCESSORY ELECTRIC EQUIPMENT | | | | | 1,214,660,973.27 | 494,019,687 | 743,560,642 | 46,176,093 | 3.80 | 16.1 |
| 325.00 | MISCELLANEOUS POWER PLANT EQUIPMENT | | | | | | | | | | |
| | BRUNSWICK UNIT 1 | 09-2036 | 50-R1.5 | * | (1) | 201,192,590.16 | 72,402,768 | 130,801,748 | 7,865,762 | 3.91 | 16.6 |
| | BRUNSWICK UNIT 2 | 12-2034 | 50-R1.5 | * | (1) | 68,906,220.33 | 31,605,240 | 37,990,042 | 2,534,043 | 3.68 | 15.0 |
| | HARRIS UNIT 1 | 10-2046 | 50-R1.5 | * | (2) | 247,301,101.58 | 110,487,995 | 141,759,129 | 5,889,127 | 2.38 | 24.1 |
| | HARRIS DISALLOWANCE | 10-2046 | | | | (55,577,154.00) | (35,564,599) | (20,012,555) | (719,014) | 1.29 | 27.8 |
| | ROBINSON UNIT 2 | 07-2030 | 50-R1.5 | * | (1) | 190,043,010.80 | 57,228,953 | 134,714,488 | 12,040,133 | 6.34 | 11.2 |
| | TOTAL MISCELLANEOUS PLANT EQUIPMENT | | | | | 651,865,768.87 | 236,160,357 | 425,252,852 | 27,610,051 | 4.24 | 15.4 |
| | **TOTAL NUCLEAR PRODUCTION PLANT** | | | | | **8,840,958,165.58** | **4,022,278,903** | **4,959,354,336** | **292,257,258** | **3.31** | **17.0** |
| | **HYDRAULIC PRODUCTION PLANT** | | | | | | | | | | |
| 331.00 | STRUCTURES AND IMPROVEMENTS | | | | | | | | | | |
| | BLEWETT | 06-2055 | 110-R2 | * | (33) | 6,620,300.84 | 2,221,068 | 6,583,932 | 187,401 | 2.83 | 35.1 |
| | MARSHALL | 06-2035 | 110-R2 | * | (16) | 1,523,286.57 | 36,589 | 1,730,423 | 107,146 | 7.03 | 16.2 |
| | TILLERY | 06-2055 | 110-R2 | * | (29) | 6,634,057.32 | 1,449,284 | 7,108,649 | 202,328 | 3.05 | 35.1 |
| | WALTERS | 06-2034 | 110-R2 | * | (6) | 3,472,324.03 | 1,969,353 | 1,711,310 | 112,577 | 3.24 | 15.2 |
| | TOTAL STRUCTURES AND IMPROVEMENTS | | | | | 18,249,968.76 | 5,676,294 | 17,134,314 | 609,452 | 3.34 | 28.1 |
| 332.00 | RESERVOIRS, DAMS AND WATERWAYS | | | | | | | | | | |
| | BLEWETT | 06-2055 | 120-R3 | * | (33) | 8,275,323.29 | 5,471,755 | 5,534,425 | 160,135 | 1.94 | 34.6 |
| | MARSHALL | 06-2035 | 120-R3 | * | (16) | 4,071,208.19 | 2,374,604 | 2,347,997 | 143,440 | 3.52 | 16.4 |
| | TILLERY | 06-2055 | 120-R3 | * | (29) | 6,796,645.31 | 4,942,178 | 3,825,494 | 110,074 | 1.62 | 34.8 |
| | WALTERS | 06-2034 | 120-R3 | * | (6) | 34,543,362.20 | 18,258,190 | 18,357,774 | 1,195,944 | 3.46 | 15.4 |
| | TOTAL RESERVOIRS, DAMS AND WATERWAYS | | | | | 53,686,538.99 | 31,046,729 | 30,065,690 | 1,609,593 | 3.00 | 18.7 |

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT | PROBABLE RETIREMENT DATE | SURVIVOR CURVE | | NET SALVAGE PERCENT | ORIGINAL COST AS OF DECEMBER 31, 2018 | BOOK RESERVE | FUTURE ACCRUALS | CALCULATED ANNUAL ACCRUAL AMOUNT | CALCULATED ANNUAL ACCRUAL RATE | COMPOSITE REMAINING LIFE |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | | (4) | (5) | (6) | (7) | (8) | (9)=(8)/(5) | (10) |
| 333.00 | WATER WHEELS, TURBINES AND GENERATORS | | | | | | | | | | |
| | BLEWETT | 06-2055 | 75-R1.5 | * | (33) | 13,436,525.48 | 255,189 | 17,615,390 | 536,807 | 4.00 | 32.8 |
| | MARSHALL | 06-2035 | 75-R1.5 | * | (16) | 6,041,207.23 | 4,039,831 | 2,967,969 | 189,470 | 3.14 | 15.7 |
| | TILLERY | 06-2055 | 75-R1.5 | * | (29) | 14,142,264.87 | 1,061,347 | 17,182,175 | 530,595 | 3.75 | 32.4 |
| | WALTERS | 06-2034 | 75-R1.5 | * | (6) | 4,456,120.96 | 2,409,069 | 2,314,420 | 155,664 | 3.49 | 14.9 |
| | TOTAL WATER WHEELS, TURBINES AND GENERATORS | | | | | 38,076,118.54 | 7,765,436 | 40,079,954 | 1,412,536 | 3.71 | 28.4 |
| 334.00 | ACCESSORY ELECTRIC EQUIPMENT | | | | | | | | | | |
| | BLEWETT | 06-2055 | 55-R1 | * | (33) | 7,543,722.48 | (213,543) | 10,246,694 | 338,949 | 4.49 | 30.2 |
| | MARSHALL | 06-2035 | 55-R1 | * | (16) | 1,179,515.99 | 773,248 | 594,991 | 40,208 | 3.41 | 14.8 |
| | TILLERY | 06-2055 | 55-R1 | * | (29) | 3,853,242.31 | 944,048 | 4,026,634 | 137,612 | 3.57 | 29.3 |
| | WALTERS | 06-2034 | 55-R1 | * | (6) | 13,242,973.33 | 1,362,762 | 12,674,790 | 856,757 | 6.47 | 14.8 |
| | TOTAL ACCESSORY ELECTRIC EQUIPMENT | | | | | 25,819,454.11 | 2,866,514 | 27,543,109 | 1,373,526 | 5.32 | 20.1 |
| 335.00 | MISCELLANEOUS POWER PLANT EQUIPMENT | | | | | | | | | | |
| | BLEWETT | 06-2055 | 55-S0 | * | (33) | 1,826,329.58 | 422,693 | 2,006,325 | 66,903 | 3.66 | 30.0 |
| | MARSHALL | 06-2035 | 55-S0 | * | (16) | 200,696.66 | 66,551 | 166,257 | 10,921 | 5.44 | 15.2 |
| | TILLERY | 06-2055 | 55-S0 | * | (29) | 1,227,560.24 | 602,303 | 981,249 | 32,943 | 2.68 | 29.8 |
| | WALTERS | 06-2034 | 55-S0 | * | (6) | 1,756,787.00 | 448,826 | 1,413,368 | 96,765 | 5.51 | 14.6 |
| | TOTAL MISCELLANEOUS PLANT EQUIPMENT | | | | | 5,011,373.48 | 1,540,374 | 4,567,199 | 207,532 | 4.14 | 22.0 |
| 336.00 | ROADS, RAILROADS, AND BRIDGES | | | | | | | | | | |
| | MARSHALL | 06-2035 | 75-R3 | * | (16) | 12,946.58 | 9,238 | 5,780 | 364 | 2.81 | 15.9 |
| | WALTERS | 06-2034 | 75-R3 | * | (6) | 8,258.48 | 8,473 | 281 | 24 | 0.29 | 11.7 |
| | TOTAL ROADS, RAILROADS, AND BRIDGES | | | | | 21,205.06 | 17,711 | 6,061 | 388 | 1.83 | 15.6 |
| | **TOTAL HYDRAULIC PRODUCTION PLANT** | | | | | **140,864,658.94** | **48,913,058** | **119,396,327** | **5,213,027** | **3.70** | **22.9** |
| | **OTHER PRODUCTION PLANT** | | | | | | | | | | |
| 341.00 | STRUCTURES AND IMPROVEMENTS | | | | | | | | | | |
| | ASHEVILLE IC TURBINE | 06-2039 | 50-S1 | * | (3) | 31,762,836.46 | 15,086,579 | 17,629,142 | 975,677 | 3.07 | 18.1 |
| | BLEWETT IC TURBINES | 06-2024 | 50-S1 | * | (7) | 979,562.66 | 987,420 | 60,712 | 11,136 | 1.14 | 5.50 |
| | DARLINGTON IC TURBINE UNITS 1-11 | 06-2020 | 50-S1 | * | (7) | 362,282.66 | 1,161,265 | (773,623) | 0 | - | - |
| | DARLINGTON IC TURBINE UNITS 12 AND 13 | 06-2037 | 50-S1 | * | (7) | 8,403,245.66 | 7,799,625 | 1,191,848 | 69,646 | 0.83 | 17.1 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 50-S1 | * | (4) | 9,013,914.23 | 4,506,042 | 4,868,429 | 254,463 | 2.82 | 19.1 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14) | 06-2049 | 50-S1 | * | (4) | 1,356,819.84 | 323,439 | 1,087,654 | 40,347 | 2.97 | 27.0 |
| | SMITH IC TURBINES (RICHMOND COUNTY) | 06-2041 | 50-S1 | * | (2) | 19,344,678.47 | 7,843,041 | 11,888,531 | 579,000 | 2.99 | 20.5 |
| | SUTTON BLACKSTART | 06-2057 | 50-S1 | * | (9) | 11,574,792.86 | 4,616,347 | 8,000,177 | 231,353 | 2.00 | 34.6 |
| | WEATHERSPOON IC TURBINES | 06-2024 | 50-S1 | * | (21) | 3,568,977.41 | 3,833,880 | 484,582 | 92,356 | 2.59 | 5.2 |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 50-S1 | * | (4) | 47,694,242.52 | 40,526,455 | 9,075,557 | 440,153 | 0.92 | 20.6 |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 50-S1 | * | (8) | 40,103,160.35 | 7,907,269 | 35,404,144 | 1,232,177 | 3.07 | 28.7 |
| | SUTTON COMBINED CYCLE | 06-2053 | 50-S1 | * | (3) | 13,462,878.60 | (1,895,584) | 15,762,349 | 512,673 | 3.81 | 30.7 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 50-S1 | * | (6) | 25,476,302.18 | 7,358,309 | 19,646,572 | 711,705 | 2.79 | 27.6 |
| | TOTAL STRUCTURES AND IMPROVEMENTS | | | | | 213,103,693.90 | 100,054,088 | 124,326,074 | 5,150,686 | 2.42 | 24.1 |
| 341.20 | STRUCTURES AND IMPROVEMENTS - SOLAR | | | | | | | | | | |
| | CAMP LEJUNE | 06-2040 | 30-S2.5 | * | (9) | 26,130.74 | 1,617 | 26,865 | 1,307 | 5.00 | 20.6 |
| | FAYETTEVILLE | 06-2040 | 30-S2.5 | * | (11) | 3,957.51 | 248 | 4,145 | 204 | 5.15 | 20.3 |
| | ELM CITY | 06-2041 | 30-S2.5 | * | (15) | 3,925.80 | 248 | 4,267 | 203 | 5.17 | 21.0 |
| | TOTAL STRUCTURES AND IMPROVEMENTS - SOLAR | | | | | 34,014.05 | 2,113 | 35,277 | 1,714 | 5.04 | 20.6 |
| 342.00 | FUEL HOLDERS, PRODUCERS AND ACCESSORIES | | | | | | | | | | |
| | ASHEVILLE IC TURBINE | 06-2039 | 45-R2 | * | (3) | 5,115,723.34 | 2,495,453 | 2,773,742 | 148,602 | 2.90 | 18.7 |
| | BLEWETT IC TURBINES | 06-2024 | 45-R2 | * | (7) | 413,479.62 | 403,237 | 39,186 | 7,229 | 1.75 | 5.4 |
| | DARLINGTON IC TURBINE UNITS 1-11 | 06-2020 | 45-R2 | * | (7) | 5,048,367.44 | 5,817,173 | (415,419) | 0 | - | - |
| | DARLINGTON IC TURBINE UNITS 12 AND 13 | 06-2037 | 45-R2 | * | (7) | 7,243,963.20 | 5,872,288 | 1,878,753 | 108,699 | 1.50 | 17.3 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 45-R2 | * | (4) | 7,363,988.43 | 3,459,288 | 4,199,260 | 219,470 | 2.98 | 19.1 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14) | 06-2049 | 45-R2 | * | (4) | 1,461,178.80 | 360,131 | 1,159,495 | 43,476 | 2.98 | 26.7 |
| | SMITH IC TURBINES (RICHMOND COUNTY) | 06-2041 | 45-R2 | * | (2) | 8,473,790.16 | 3,354,658 | 5,288,608 | 267,152 | 3.15 | 19.8 |
| | SUTTON BLACKSTART | 06-2057 | 45-R2 | * | (9) | 5,990,884.76 | 137,567 | 6,392,498 | 188,103 | 3.14 | 34.0 |
| | WEATHERSPOON IC TURBINES | 06-2024 | 45-R2 | * | (21) | 1,651,095.21 | 1,242,908 | 754,917 | 140,115 | 8.49 | 5.4 |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 45-R2 | * | (4) | 13,523,522.65 | 5,631,253 | 8,433,211 | 405,772 | 3.00 | 20.8 |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 45-R2 | * | (8) | 22,575,250.21 | 4,383,495 | 19,997,775 | 702,612 | 3.11 | 28.5 |
| | SUTTON COMBINED CYCLE | 06-2053 | 45-R2 | * | (3) | 19,656,537.55 | (5,290,149) | 25,536,382 | 835,790 | 4.25 | 30.6 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 45-R2 | * | (6) | 25,423,310.37 | 2,091,783 | 24,856,926 | 845,788 | 3.33 | 29.4 |
| | TOTAL FUEL HOLDERS, PRODUCERS AND ACCESSORIES | | | | | 123,941,091.74 | 29,959,084 | 100,895,334 | 3,912,808 | 3.16 | 25.8 |

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT | PROBABLE RETIREMENT DATE | SURVIVOR CURVE | NET SALVAGE PERCENT | ORIGINAL COST AS OF DECEMBER 31, 2018 | BOOK RESERVE | FUTURE ACCRUALS | CALCULATED ANNUAL ACCRUAL AMOUNT | CALCULATED ANNUAL ACCRUAL RATE | COMPOSITE REMAINING LIFE |
|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9)=(8)/(5) | (10) |
| 343.00 | PRIME MOVERS | | | | | | | | | |
| | ASHEVILLE IC TURBINE | 06-2039 | 30-R0.5 * | (3) | 51,871,873.24 | 8,773,161 | 44,654,868 | 2,634,563 | 5.08 | 16.9 |
| | BLEWETT IC TURBINES | 06-2024 | 30-R0.5 * | (7) | 8,455,727.27 | 7,408,641 | 1,638,987 | 336,664 | 3.98 | 4.9 |
| | DARLINGTON IC TURBINE UNITS 1-11 | 06-2020 | 30-R0.5 * | (7) | 22,476,731.53 | 9,641,480 | 14,408,622 | 9,767,204 | 43.45 | 1.5 |
| | DARLINGTON IC TURBINE UNITS 12 AND 13 | 06-2037 | 30-R0.5 * | (7) | 39,502,461.61 | (379,217) | 42,646,851 | 2,901,267 | 7.34 | 14.7 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 30-R0.5 * | (4) | 121,712,253.32 | 48,127,557 | 78,453,186 | 4,737,903 | 3.89 | 16.6 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14) | 06-2049 | 30-R0.5 * | (4) | 61,526,436.54 | 14,386,219 | 49,601,275 | 2,326,209 | 3.78 | 21.3 |
| | SMITH IC TURBINES (RICHMOND COUNTY) | 06-2041 | 30-R0.5 * | (2) | 230,437,633.01 | (28,820,222) | 263,866,608 | 14,883,340 | 6.46 | 17.7 |
| | SUTTON BLACKSTART | 06-2057 | 30-R0.5 * | (9) | 65,019,558.96 | 1,224,776 | 69,646,543 | 2,651,182 | 4.08 | 26.3 |
| | WEATHERSPOON IC TURBINES | 06-2024 | 30-R0.5 * | (21) | 12,638,464.88 | 14,847,046 | 445,496 | 86,525 | 0.68 | 5.1 |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 30-R0.5 * | (4) | 114,272,116.59 | (21,766,797) | 140,609,798 | 8,046,676 | 7.04 | 17.5 |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 30-R0.5 * | (8) | 236,173,460.30 | 45,471,509 | 209,595,828 | 9,344,070 | 3.96 | 22.4 |
| | SUTTON COMBINED CYCLE | 06-2053 | 30-R0.5 * | (3) | 361,361,292.77 | 12,434,111 | 359,768,021 | 15,105,488 | 4.18 | 23.8 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 30-R0.5 * | (6) | 443,686,010.74 | 30,441,659 | 439,865,513 | 19,052,498 | 4.29 | 23.1 |
| | TOTAL PRIME MOVERS | | | | 1,769,134,020.76 | 141,789,923 | 1,715,201,596 | 91,873,589 | 5.19 | 18.7 |
| 343.10 | PRIME MOVERS - ROTABLE PARTS | | | | | | | | | |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 6-L0.5 * | 40 | 39,318,264.60 | 3,453,628 | 20,137,331 | 4,840,705 | 12.31 | 4.2 |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 6-L0.5 * | 40 | 44,987,832.65 | 7,894,446 | 19,098,254 | 5,974,679 | 13.28 | 3.2 |
| | SUTTON COMBINED CYCLE | 06-2053 | 6-L0.5 * | 40 | 29,483,115.01 | 5,468,284 | 12,221,585 | 3,577,906 | 12.14 | 3.4 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 6-L0.5 * | 40 | 56,542,095.59 | 6,820,315 | 27,104,942 | 7,057,740 | 12.48 | 3.8 |
| | TOTAL PRIME MOVERS - ROTABLE PARTS | | | | 170,331,307.85 | 23,636,673 | 78,562,112 | 21,451,030 | 12.59 | 3.7 |
| 344.00 | GENERATORS | | | | | | | | | |
| | ASHEVILLE IC TURBINE | 06-2039 | 50-R2 * | (3) | 7,769,953.49 | 3,627,517 | 4,375,535 | 233,653 | 3.01 | 18.7 |
| | BLEWETT IC TURBINES | 06-2024 | 50-R2 * | (7) | 1,988,284.95 | 2,204,189 | (76,724) | 0 | - | - |
| | DARLINGTON IC TURBINE UNITS 1-11 | 06-2020 | 50-R2 * | (7) | 12,472,614.73 | 8,742,209 | 4,603,489 | 3,097,560 | 24.83 | 1.5 |
| | DARLINGTON IC TURBINE UNITS 12 AND 13 | 06-2037 | 50-R2 * | (7) | 17,131,838.45 | 5,675,300 | 12,655,767 | 735,468 | 4.29 | 17.2 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 50-R2 * | (4) | 22,068,501.33 | 10,644,166 | 12,307,075 | 632,402 | 2.87 | 19.5 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14) | 06-2049 | 50-R2 * | (4) | 13,021,303.33 | 2,807,071 | 10,735,084 | 390,823 | 3.00 | 27.5 |
| | SMITH IC TURBINES (RICHMOND COUNTY) | 06-2041 | 50-R2 * | (2) | 37,046,160.65 | (38,773,572) | 76,560,656 | 3,735,595 | 10.08 | 20.5 |
| | SUTTON BLACKSTART | 06-2057 | 50-R2 * | (9) | 2,145,710.72 | 274,377 | 2,064,447 | 59,357 | 2.77 | 34.8 |
| | WEATHERSPOON IC TURBINES | 06-2024 | 50-R2 * | (21) | 2,095,743.68 | 2,565,954 | (30,104) | 0 | - | - |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 50-R2 * | (4) | 40,449,074.75 | 62,933,029 | (20,865,991) | 0 | - | - |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 50-R2 * | (8) | 31,516,637.44 | 6,327,771 | 27,710,198 | 946,600 | 3.00 | 29.3 |
| | SUTTON COMBINED CYCLE | 06-2053 | 50-R2 * | (3) | 44,450,493.34 | 4,229,533 | 41,554,475 | 1,335,598 | 3.00 | 31.1 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 50-R2 * | (6) | 55,122,184.33 | 5,647,199 | 52,782,316 | 1,748,825 | 3.17 | 30.2 |
| | TOTAL GENERATORS | | | | 287,278,501.19 | 76,904,743 | 224,376,223 | 12,915,881 | 4.50 | 17.4 |
| 344.20 | GENERATORS - SOLAR | | | | | | | | | |
| | CAMP LEJUNE | 06-2040 | 25-S2.5 * | (9) | 15,956,191.94 | 1,973,252 | 15,418,997 | 822,344 | 5.15 | 18.8 |
| | FAYETTEVILLE | 06-2040 | 25-S2.5 * | (11) | 32,469,234.56 | 4,022,825 | 32,018,026 | 1,708,709 | 5.26 | 18.7 |
| | ELM CITY | 06-2041 | 25-S2.5 * | (15) | 51,863,631.58 | 5,776,472 | 53,866,704 | 2,731,170 | 5.27 | 19.7 |
| | WARSAW | 06-2040 | 25-S2.5 * | (12) | 87,181,902.80 | 10,880,666 | 86,763,065 | 4,629,736 | 5.31 | 18.7 |
| | TOTAL GENERATORS - SOLAR | | | | 187,470,960.88 | 22,653,215 | 188,066,792 | 9,891,959 | 5.28 | 19.0 |
| 345.00 | ACCESSORY ELECTRIC EQUIPMENT | | | | | | | | | |
| | ASHEVILLE IC TURBINE | 06-2039 | 50-R1.5 * | (3) | 13,502,429.56 | 3,492,810 | 10,414,693 | 549,433 | 4.07 | 19.0 |
| | BLEWETT IC TURBINES | 06-2024 | 50-R1.5 * | (7) | 1,418,891.29 | 1,450,318 | 67,896 | 12,494 | 0.88 | 5.4 |
| | DARLINGTON IC TURBINE UNITS 1-11 | 06-2020 | 50-R1.5 * | (7) | 4,869,111.48 | 4,598,032 | 611,918 | 410,605 | 8.43 | 1.5 |
| | DARLINGTON IC TURBINE UNITS 12 AND 13 | 06-2037 | 50-R1.5 * | (7) | 10,782,807.93 | 4,167,477 | 7,370,127 | 433,757 | 4.02 | 17.0 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 50-R1.5 * | (4) | 19,926,915.26 | 9,556,455 | 11,167,537 | 576,702 | 2.89 | 19.4 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14) | 06-2049 | 50-R1.5 * | (4) | 10,599,164.94 | 2,350,198 | 8,672,934 | 321,295 | 3.03 | 27.0 |
| | SMITH IC TURBINES (RICHMOND COUNTY) | 06-2041 | 50-R1.5 * | (2) | 29,257,399.18 | 11,618,321 | 18,224,226 | 894,076 | 3.06 | 20.4 |
| | SUTTON BLACKSTART | 06-2057 | 50-R1.5 * | (9) | 13,595,340.46 | 1,958,624 | 12,860,297 | 379,136 | 2.79 | 33.9 |
| | WEATHERSPOON IC TURBINES | 06-2024 | 50-R1.5 * | (21) | 3,003,206.27 | 1,866,086 | 1,767,794 | 329,700 | 10.98 | 5.4 |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 50-R1.5 * | (4) | 21,653,205.44 | 7,093,541 | 15,425,793 | 723,937 | 3.34 | 21.3 |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 50-R1.5 * | (8) | 51,327,924.43 | 8,850,051 | 46,584,108 | 1,621,061 | 3.16 | 28.7 |
| | SUTTON COMBINED CYCLE | 06-2053 | 50-R1.5 * | (3) | 62,940,670.78 | 3,515,905 | 61,312,986 | 2,012,729 | 3.20 | 30.5 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 50-R1.5 * | (6) | 76,581,369.69 | 6,263,965 | 74,912,286 | 2,531,320 | 3.31 | 29.6 |
| | TOTAL ACCESSORY ELECTRIC EQUIPMENT | | | | 319,458,436.71 | 66,781,781 | 269,392,595 | 10,796,245 | 3.38 | 25.0 |
| 345.20 | ACCESSORY ELECTRIC EQUIPMENT - SOLAR | | | | | | | | | |
| | CAMP LEJUNE | 06-2040 | 25-S2.5 * | (9) | 2,761,117.30 | 351,375 | 2,658,243 | 141,616 | 5.13 | 18.8 |
| | FAYETTEVILLE | 06-2040 | 25-S2.5 * | (11) | 533,260.74 | 68,266 | 523,653 | 28,033 | 5.26 | 18.7 |
| | ELM CITY | 06-2041 | 25-S2.5 * | (15) | 133,458.18 | 16,509 | 136,968 | 6,990 | 5.24 | 19.6 |
| | WARSAW | 06-2040 | 25-S2.5 * | (12) | 1,258,878.46 | 163,411 | 1,246,533 | 66,731 | 5.30 | 18.7 |
| | TOTAL ACCESSORY ELECTRIC EQUIPMENT - SOLAR | | | | 4,686,714.68 | 599,561 | 4,565,397 | 243,370 | 5.19 | 18.8 |

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT (1) | PROBABLE RETIREMENT DATE (2) | SURVIVOR CURVE (3) | NET SALVAGE PERCENT (4) | ORIGINAL COST AS OF DECEMBER 31, 2018 (5) | BOOK RESERVE (6) | FUTURE ACCRUALS (7) | CALCULATED ANNUAL ACCRUAL AMOUNT (8) | CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5) | COMPOSITE REMAINING LIFE (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| 346.00 | MISCELLANEOUS POWER PLANT EQUIPMENT | | | | | | | | | |
| | ASHEVILLE IC TURBINE | 06-2039 | 30-S1 * | (3) | 3,414,473.38 | 900,837 | 2,616,070 | 165,627 | 4.85 | 15.8 |
| | BLEWETT IC TURBINES | 06-2024 | 30-S1 * | (7) | 204,914.55 | 80,191 | 139,068 | 26,575 | 12.97 | 5.2 |
| | DARLINGTON IC TURBINE UNITS 1-11 | 06-2020 | 30-S1 * | (7) | 90,349.83 | (168,029) | 264,703 | 177,654 | 196.63 | 1.5 |
| | DARLINGTON IC TURBINE UNITS 12 AND 13 | 06-2037 | 30-S1 * | (7) | 1,432,545.23 | 806,305 | 726,518 | 44,312 | 3.09 | 16.4 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 30-S1 * | (4) | 1,316,904.66 | 889,548 | 480,033 | 31,177 | 2.37 | 15.4 |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNIT 14) | 06-2049 | 30-S1 * | (4) | 1,125,769.23 | 408,002 | 762,798 | 38,046 | 3.38 | 20.0 |
| | SMITH IC TURBINES (RICHMOND COUNTY) | 06-2041 | 30-S1 * | (2) | 7,653,551.58 | (2,805,709) | 10,612,331 | 624,277 | 8.16 | 17.0 |
| | SUTTON BLACKSTART | 06-2057 | 30-S1 * | (9) | 1,861,416.34 | 26,901 | 2,002,043 | 73,523 | 3.95 | 27.2 |
| | WEATHERSPOON IC TURBINES | 06-2024 | 30-S1 * | (21) | 721,477.59 | 215,281 | 657,707 | 123,221 | 17.08 | 5.3 |
| | SMITH COMBINED CYCLE POWER BLOCK 4 (RICHMOND COUNTY) | 06-2042 | 30-S1 * | (4) | 4,901,411.09 | 4,552,021 | 545,446 | 26,262 | 0.54 | 20.8 |
| | SMITH COMBINED CYCLE POWER BLOCK 5 (RICHMOND COUNTY) | 06-2051 | 30-S1 * | (8) | 8,419,845.29 | 1,797,141 | 7,296,292 | 337,867 | 4.01 | 21.6 |
| | SUTTON COMBINED CYCLE | 06-2053 | 30-S1 * | (3) | 8,363,725.23 | 630,158 | 7,984,479 | 335,284 | 4.01 | 23.8 |
| | H.F. LEE COMBINED CYCLE (WAYNE COUNTY) | 06-2052 | 30-S1 * | (6) | 11,795,130.01 | 1,356,717 | 11,146,121 | 489,752 | 4.15 | 22.8 |
| | TOTAL MISCELLANEOUS PLANT EQUIPMENT | | | | 51,301,514.01 | 8,689,364 | 45,233,609 | 2,493,577 | 4.86 | 18.1 |
| 346.20 | MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR | | | | | | | | | |
| | ELM CITY | 06-2041 | 30-S2.5 * | (15) | 10,069.36 | 467 | 11,112 | 528 | 5.24 | 21.0 |
| | WARSAW | 06-2040 | 30-S2.5 * | (12) | 19,111.49 | 547 | 20,858 | 1,017 | 5.32 | 20.5 |
| | TOTAL MISCELLANEOUS PLANT EQUIPMENT - SOLAR | | | | 29,180.85 | 1,015 | 31,970 | 1,545 | 5.29 | 20.7 |
| | **TOTAL OTHER PRODUCTION PLANT** | | | | **3,126,769,436.62** | **471,071,560** | **2,750,686,979** | **158,732,404** | **5.08** | **17.3** |
| | **TOTAL PRODUCTION** | | | | **16,087,542,172.24** | **6,610,898,913** | **9,920,168,088** | **668,373,584** | **4.15** | **14.8** |
| | **TRANSMISSION PLANT** | | | | | | | | | |
| 352.00 | STRUCTURES AND IMPROVEMENTS | | 60-R3 | (10) | 90,193,203.79 | 30,731,591 | 68,480,933 | 1,622,028 | 1.80 | 42.2 |
| 353.00 | STATION EQUIPMENT | | 55-R1.5 | (15) | 1,070,174,832.08 | 233,041,480 | 997,659,577 | 23,628,452 | 2.21 | 42.2 |
| 354.00 | TOWERS AND FIXTURES | | 75-R4 | (20) | 78,936,364.53 | 46,268,549 | 48,455,088 | 936,307 | 1.19 | 51.8 |
| 355.00 | POLES AND FIXTURES | | 49-R1.5 | (40) | 743,280,241.54 | 262,890,321 | 777,702,017 | 19,031,917 | 2.56 | 40.9 |
| 356.00 | OVERHEAD CONDUCTORS AND DEVICES | | 65-R2.5 | (40) | 551,039,389.11 | 187,315,525 | 584,139,620 | 11,383,033 | 2.07 | 51.3 |
| 357.00 | UNDERGROUND CONDUIT | | 60-R4 | 0 | 32,286.46 | (584) | 32,870 | 559 | 1.73 | 58.8 |
| 358.00 | UNDERGROUND CONDUCTORS AND DEVICES | | 45-S2.5 | 0 | 21,603,999.00 | 1,688,307 | 19,915,692 | 504,195 | 2.33 | 39.5 |
| 359.00 | ROADS AND TRAILS | | 75-R3 | 0 | 312,522.87 | 68,523 | 244,000 | 4,253 | 1.36 | 57.4 |
| | **TOTAL TRANSMISSION PLANT** | | | | **2,555,572,839.38** | **762,003,713** | **2,496,629,797** | **57,110,744** | **2.23** | **43.7** |
| | **DISTRIBUTION PLANT** | | | | | | | | | |
| 361.00 | STRUCTURES AND IMPROVEMENTS | | 60-R2 | (15) | 127,079,158.04 | 48,130,054 | 98,010,977 | 2,021,366 | 1.59 | 48.5 |
| 362.00 | STATION EQUIPMENT | | 48-R1 | (15) | 683,055,387.27 | 199,280,175 | 586,233,520 | 15,332,138 | 2.24 | 38.2 |
| 364.00 | POLES, TOWERS AND FIXTURES | | 45-R2.5 | (100) | 855,785,431.01 | 618,419,612 | 1,093,151,250 | 33,556,194 | 3.92 | 32.6 |
| 365.00 | OVERHEAD CONDUCTORS AND DEVICES | | 45-R1 | (30) | 1,208,423,459.24 | 617,880,131 | 953,070,366 | 24,922,045 | 2.06 | 38.2 |
| 366.00 | UNDERGROUND CONDUIT | | 46-S2.5 | (15) | 199,779,066.87 | 72,884,435 | 156,861,492 | 4,725,775 | 2.37 | 33.2 |
| 367.00 | UNDERGROUND CONDUCTORS AND DEVICES | | 42-S2 | (5) | 1,134,635,170.25 | 622,088,309 | 569,278,619 | 18,411,036 | 1.62 | 30.9 |
| 368.00 | LINE TRANSFORMERS | | 40-R2 | (5) | 1,131,254,323.64 | 379,239,615 | 808,577,425 | 27,806,592 | 2.46 | 29.1 |
| 369.00 | SERVICES | | 55-R3 | (20) | 681,775,180.43 | 370,866,150 | 447,264,066 | 10,868,784 | 1.59 | 41.2 |
| 370.00 | METERING EQUIPMENT | | 28-R4 | (10) | 51,889,323.64 | 28,415,375 | 28,662,881 | 1,063,840 | 2.05 | 26.9 |
| 370.01 | METERS | | 28-R4 | (5) | 142,517,522.33 | 81,602,020 | 68,041,378 | 7,007,351 | ** | 9.7 |
| 370.02 | METERS - UOF | | 15-S2.5 | 0 | 69,710,613.08 | 2,407,594 | 67,303,019 | 4,645,856 | 6.66 | 14.5 |
| 371.00 | INSTALLATIONS ON CUSTOMERS' PREMISES | | 26-S0.5 | (10) | 318,551,648.97 | 252,936,350 | 97,470,464 | 4,405,748 | 1.38 | 22.1 |
| 373.00 | STREET LIGHTING AND SIGNAL SYSTEMS | | 25-R1 | (10) | 264,812,433.62 | 14,493,162 | 276,800,515 | 12,840,929 | 4.85 | 21.6 |
| | **TOTAL DISTRIBUTION PLANT** | | | | **6,869,268,718.39** | **3,308,642,984** | **5,250,725,972** | **167,607,654** | **2.44** | **31.3** |

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT (1) | PROBABLE RETIREMENT DATE (2) | SURVIVOR CURVE (3) | NET SALVAGE PERCENT (4) | ORIGINAL COST AS OF DECEMBER 31, 2018 (5) | BOOK RESERVE (6) | FUTURE ACCRUALS (7) | CALCULATED ANNUAL ACCRUAL AMOUNT (8) | CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5) | COMPOSITE REMAINING LIFE (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| | **GENERAL PLANT** | | | | | | | | | |
| 390.00 | STRUCTURES AND IMPROVEMENTS | | 45-R1.5 | (5) | 156,446,136.21 | 31,155,047 | 133,113,396 | 3,805,402 | 2.43 | 35.0 |
| 391.00 | OFFICE FURNITURE AND EQUIPMENT | | | | | | | | | |
| | FULLY ACCRUED | | FULLY ACCRUED | | 10,200,214.55 | 10,200,215 | 0 | 0 | - | - |
| | AMORTIZED | | 15-SQ | 0 | 14,520,609.30 | 2,860,000 | 11,660,609 | 968,950 | 6.67 | 12.0 |
| | TOTAL OFFICE FURNITURE AND EQUIPMENT | | | | 24,720,823.85 | 13,060,215 | 11,660,609 | 968,950 | 3.92 | 12.0 |
| 391.10 | OFFICE FURNITURE AND EQUIPMENT - EDP | | 8-SQ | 0 | 61,586,228.38 | 20,800,000 | 40,786,228 | 7,696,591 | 12.50 | 5.3 |
| 392.00 | TRANSPORTATION EQUIPMENT | | 11-L2 | 15 | 69,975,818.26 | 34,325,441 | 25,154,004 | 4,493,909 | 6.42 | 5.6 |
| 393.00 | STORES EQUIPMENT | | 20-SQ | 0 | 2,059,932.97 | 822,000 | 1,237,933 | 102,894 | 5.00 | 12.0 |
| 394.00 | TOOLS, SHOP AND GARAGE EQUIPMENT | | 20-SQ | 0 | 90,247,659.07 | 21,910,000 | 68,337,659 | 4,508,503 | 5.00 | 15.2 |
| 395.00 | LABORATORY EQUIPMENT | | 15-SQ | 0 | 6,739,788.51 | 3,908,000 | 2,831,789 | 449,309 | 6.67 | 6.3 |
| 396.00 | POWER OPERATED EQUIPMENT | | 12-S6 | 0 | 5,679,686.30 | 2,225,815 | 3,453,872 | 412,343 | 7.26 | 8.4 |
| 397.00 | COMMUNICATION EQUIPMENT | | | | | | | | | |
| | FULLY ACCRUED | | FULLY ACCRUED | | 59,435,956.41 | 59,435,956 | 0 | 0 | - | - |
| | AMORTIZED | | 10-SQ | 0 | 120,535,862.75 | 53,890,000 | 66,645,863 | 12,049,716 | 10.00 | 5.5 |
| | TOTAL COMMUNICATION EQUIPMENT | | | | 179,971,819.16 | 113,325,956 | 66,645,863 | 12,049,716 | 6.70 | 5.5 |
| 398.00 | MISCELLANEOUS EQUIPMENT | | 20-SQ | 0 | 23,040,257.68 | 15,615,000 | 7,425,258 | 1,150,868 | 5.00 | 6.5 |
| | **TOTAL GENERAL PLANT** | | | | **620,468,150.39** | **257,147,474** | **360,646,611** | **35,638,485** | **5.74** | **10.1** |
| | **TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT** | | | | **10,045,309,708.16** | **4,327,794,170** | **8,108,002,380** | **260,356,883** | **2.59** | **31.1** |
| | **DEPRECIABLE LAND RIGHTS** | | | | | | | | | |
| 310.00 | LAND RIGHTS | | | | | | | | | |
| | ASHEVILLE UNIT 1 | 12-2027 | 100-R4 * | 0 | 919,201.95 | 1,049,268 | (130,066) | 0 | - | - |
| | MAYO UNIT 1 | 06-2029 | 100-R4 * | 0 | 3,577,117.54 | 3,213,884 | 363,233 | 34,725 | 0.97 | 10.50 |
| | ROXBORO UNIT 1 | 06-2028 | 100-R4 * | 0 | 1,827,202.76 | 1,910,729 | (83,526) | 0 | - | - |
| | ROXBORO UNIT 3 | 06-2029 | 100-R4 * | 0 | 3,037,934.25 | 3,151,250 | (113,316) | 0 | - | - |
| | TOTAL ACCOUNT 310 | | | | 9,361,456.50 | 9,325,132 | 36,325 | 34,725 | 0.37 | - |
| 320.00 | LAND RIGHTS | | | | | | | | | |
| | HARRIS UNIT 1 | 10-2046 | 100-R4 * | 0 | 49,809,293.03 | 33,296,139 | 16,513,154 | 601,134 | 1.21 | 27.5 |
| | ROBINSON UNIT 2 | 07-2030 | 100-R4 * | 0 | 315,919.74 | 316,714 | (794) | 0 | - | - |
| | TOTAL LAND RIGHTS | | | | 50,125,212.77 | 33,612,853 | 16,512,360 | 601,134 | 1.20 | 27.5 |
| 320.10 | RIGHTS OF WAY | | | | | | | | | |
| | BRUNSWICK UNIT 1 | 09-2036 | 100-R4 * | 0 | 9,724.11 | 8,156 | 1,568 | 90 | 0.93 | 17.4 |
| | BRUNSWICK UNIT 2 | 12-2034 | 100-R4 * | 0 | 51,363.07 | 49,976 | 1,388 | 88 | 0.17 | 15.8 |
| | ROBINSON UNIT 2 | 07-2030 | 100-R4 * | 0 | 6,141.10 | 6,141 | 0 | 0 | - | - |
| | TOTAL RIGHTS OF WAY | | | | 67,228.28 | 64,272 | 2,956 | 178 | 0.26 | 16.6 |
| | TOTAL ACCOUNT 320 | | | | 50,192,441.05 | 33,677,125 | 16,515,316 | 601,312 | 1.20 | 27.5 |
| 330.00 | LAND RIGHTS | | | | | | | | | |
| | WALTERS | 06-2034 | 110-R4 * | 0 | 80,796.94 | 50,520 | 30,277 | 2,160 | 2.67 | 14.0 |
| 330.10 | RIGHTS OF WAY | | | | | | | | | |
| | BLEWETT | 06-2055 | 110-R4 * | 0 | 9,598.14 | 6,297 | 3,301 | 195 | 2.03 | 16.9 |
| | MARSHALL | 06-2035 | 110-R4 * | 0 | 3,728.53 | 2,548 | 1,180 | 98 | 2.63 | 12.0 |
| | TILLERY | 06-2055 | 110-R4 * | 0 | 19,764.49 | 13,269 | 6,495 | 261 | 1.32 | 24.9 |
| | WALTERS | 06-2034 | 110-R4 * | 0 | 33,333.15 | 20,634 | 12,699 | 887 | 2.66 | 14.3 |
| | TOTAL RIGHTS OF WAY | | | | 66,424.31 | 42,748 | 23,675 | 1,441 | 2.17 | 16.4 |
| | TOTAL ACCOUNT 330 | | | | 147,221.25 | 93,268 | 53,952 | 3,601 | 2.45 | 15.0 |
| 340.00 | LAND RIGHTS | | | | | | | | | |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 60-R4 * | 0 | 2,048,655.08 | 1,037,253 | 1,011,402 | 49,114 | 2.40 | 20.6 |
| 340.10 | RIGHTS OF WAY | | | | | | | | | |
| | H.F. LEE IC TURBINES (WAYNE COUNTY UNITS 10-13) | 06-2040 | 60-R4 * | 0 | 2,532,367.27 | 1,106,468 | 1,425,899 | 67,739 | 2.67 | 21.0 |
| | TOTAL ACCOUNT 340.1 | | | | 4,581,022.35 | 2,143,721 | 2,437,301 | 116,853 | 2.55 | 20.9 |

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DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| | ACCOUNT (1) | PROBABLE RETIREMENT DATE (2) | SURVIVOR CURVE (3) | NET SALVAGE PERCENT (4) | ORIGINAL COST AS OF DECEMBER 31, 2018 (5) | BOOK RESERVE (6) | FUTURE ACCRUALS (7) | CALCULATED ANNUAL ACCRUAL AMOUNT (8) | CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5) | COMPOSITE REMAINING LIFE (10) |
|---|---|---|---|---|---|---|---|---|---|---|
| 350.10 | RIGHTS OF WAY | | 75-R3 | 0 | 176,749,823.75 | 68,578,311 | 108,171,513 | 2,039,608 | 1.15 | 53.0 |
| 360.00 | LAND RIGHTS | | 65-R3 | 0 | 107,521.37 | 19,073 | 88,448 | 1,586 | 1.48 | 55.8 |
| 360.10 | RIGHTS OF WAY | | 65-R3 | 0 | 23,908,367.28 | 12,009,169 | 11,899,199 | 298,919 | 1.25 | 39.8 |
| 389.10 | RIGHTS OF WAY | | 60-R3 | 0 | 51,783.33 | (670,230) | 722,014 | 27,147 | 52.42 | 26.6 |
| | **TOTAL DEPRECIABLE LAND RIGHTS** | | | | **265,099,636.88** | **125,175,569** | **139,924,068** | **3,123,751** | **1.18** | **44.8** |
| | **TOTAL ELECTRIC PLANT** | | | | **26,397,951,517.28** | **11,063,868,652** | **18,168,094,536** | **931,854,218** | **3.53** | **19.5** |
| | **RESERVE ADJUSTMENT FOR AMORTIZATION** | | | | | | | | | |
| 391.00 | OFFICE FURNITURE AND EQUIPMENT | | | | | (17,130,482) | | 3,426,096 *** | | |
| 393.00 | STORES EQUIPMENT | | | | | (762,086) | | 152,417 *** | | |
| 394.00 | TOOLS, SHOP AND GARAGE EQUIPMENT | | | | | (11,388,283) | | 2,277,657 *** | | |
| 395.00 | LABORATORY EQUIPMENT | | | | | 398,322 | | (79,664) *** | | |
| 397.00 | COMMUNICATION EQUIPMENT | | | | | (56,777,491) | | 11,355,498 *** | | |
| 398.00 | MISCELLANEOUS EQUIPMENT | | | | | (6,986,450) | | 1,397,290 *** | | |
| | **RESERVE ADJUSTMENT FOR AMORTIZATION** | | | | | **(92,646,470)** | | **18,529,294** | | |
| | **TOTAL DEPRECIABLE ELECTRIC PLANT** | | | | **26,397,951,517.28** | **10,971,222,183** | **18,168,094,536** | **950,383,512** | | |
| | **NONDEPRECIABLE AND ACCOUNTS NOT STUDIED** | | | | | | | | | |
| | NONDEPRECIABLE ACCOUNTS | | | | | | | | | |
| 301.00 | ORGANIZATION | | | | 717,237.36 | 134,172 | | | | |
| 302.00 | FRANCHISE | | | | 59,871,453.31 | 25,092,129 | | | | |
| 303.00 | SOFTWARE | | | | 466,781,699.76 | 297,605,023 | | | | |
| 310.00 | LAND | | | | 23,302,268.83 | | | | | |
| 311.00 | STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT | | | | 248,681.03 | | | | | |
| 317.00 | ARO - STEAM | | | | 827,197,087.81 | 342,312,237 | | | | |
| 320.00 | LAND | | | | 18,165,996.67 | | | | | |
| 321.00 | STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE | | | | 1,854,278.73 | | | | | |
| 326.00 | ARO - NUCLEAR | | | | 876,137,782.45 | 234,148,758 | | | | |
| 330.00 | LAND | | | | 2,681,695.37 | | | | | |
| 331.00 | STRUCTURES AND IMPROVEMENTS - OTHER - GENERAL PLANT | | | | 245,662.37 | | | | | |
| 337.00 | ARO - HYDRO | | | | 1,734,119.29 | 108,750 | | | | |
| 340.00 | LAND | | | | 5,421,028.49 | | | | | |
| 341.00 | STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE | | | | 105,999,098.00 | | | | | |
| 347.20 | ARO - OTHER PRODUCTION - SOLAR | | | | 7,642,438.48 | | | | | |
| 350.00 | LAND | | | | 14,066,210.40 | | | | | |
| 352.00 | STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE | | | | 18,335,571.33 | | | | | |
| 360.00 | LAND | | | | 51,479,536.91 | | | | | |
| 389.00 | LAND | | | | 8,096,305.23 | | | | | |
| 390.00 | STRUCTURES AND IMPROVEMENTS - CAPITAL LEASE | | | | 10,359,698.41 | | | | | |
| 399.00 | ARO - GENERAL | | | | 2,717,587.67 | 1,704,333 | | | | |
| | TOTAL NONDEPRECIABLE ACCOUNTS | | | | 2,503,055,437.90 | 901,105,401 | | | | |
| | RETIRED PLANTS | | | | | | | | | |
| | CAPE FEAR | | | | (1,328.95) | (1,329) | | | | |
| | ROBINSON ICT | | | | | 349,120 | | | | |
| | ROXBORO ICT | | | | | (146,504) | | | | |
| | TOTAL RETIRED PLANTS | | | | (1,328.95) | 201,287 | | | | |

DUKE ENERGY PROGRESS
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENT, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS AND RATES AS OF DECEMBER 31, 2018

| ACCOUNT (1) | PROBABLE RETIREMENT DATE (2) | SURVIVOR CURVE (3) | NET SALVAGE PERCENT (4) | ORIGINAL COST AS OF DECEMBER 31, 2018 (5) | BOOK RESERVE (6) | FUTURE ACCRUALS (7) | CALCULATED ANNUAL ACCRUAL AMOUNT (8) | CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(5) | COMPOSITE REMAINING LIFE (10) |
|---|---|---|---|---|---|---|---|---|---|
| MISCELLANEOUS | | | | | | | | | |
| UNSPECIFIED | | | | | (381,483) | | | | |
| NON-UTILITY | | | | | 11,814,219 | | | | |
| HARRIS ACCELERATED DEPRECIATION | | | | | 404,563,441 | | | | |
| CPL DECOMM | | | | | 96,199,655 | | | | |
| RATE DIFFERENCE | | | | | (35,009,966) | | | | |
| ARO | | | | | 1,512,496 | | | | |
| ARO CONTRA COR | | | | | (26,235,987) | | | | |
| OTHER (NO ACCOUNT ON 1085 PROVIDED) | | | | | 22,144 | | | | |
| TOTAL MISCELLANEOUS | | | | 0.00 | 452,484,518 | | | | |
| **TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED** | | | | **2,503,054,108.95** | **1,353,791,206** | | | | |
| **TOTAL PLANT** | | | | **28,901,005,626.23** | **12,325,013,388** | | | | |

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.

** Annual Accrual Amount calculated based on remaining amortization period of 9.71 years (March 2028 which is 10 years from implementation).

*** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting.

Accrual rates for the Asheville Combined Cycle Plant when placed in service by November 2019 will be as follows:

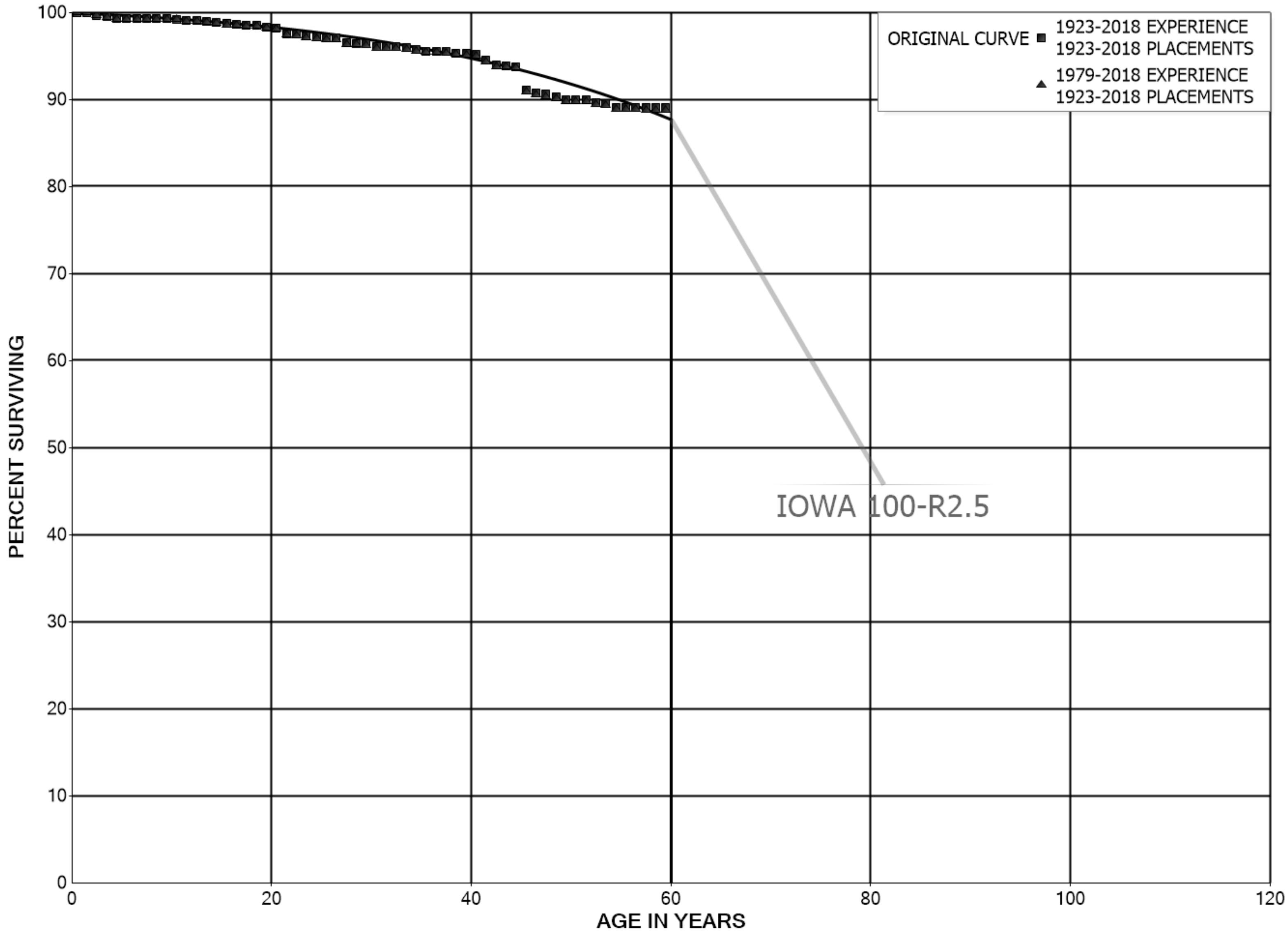
| Account | Rate |
|---|---|
| 341.00 | 2.87 |
| 342.00 | 2.93 |
| 343.00 | 3.78 |
| 343.10 | 10.68 |
| 344.00 | 2.85 |
| 345.00 | 2.93 |
| 346.00 | 3.63 |

Accrual rates for new Battery Storage Assets based on a 15-L3 survivor curve and 0% net salvage will be as follows:

| Account | Rate |
|---|---|
| 348.00 | 6.90 |
| 351.00 | 6.90 |
| 363.00 | 6.90 |

# PART VII. SERVICE LIFE STATISTICS

DUKE ENERGY PROGRESS
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 604,117,779 | 57,175 | 0.0001 | 0.9999 | 100.00 |
| 0.5 | 575,839,602 | 3,088 | 0.0000 | 1.0000 | 99.99 |
| 1.5 | 558,707,841 | 1,893,481 | 0.0034 | 0.9966 | 99.99 |
| 2.5 | 543,431,095 | 921,095 | 0.0017 | 0.9983 | 99.65 |
| 3.5 | 514,876,991 | 971,566 | 0.0019 | 0.9981 | 99.48 |
| 4.5 | 480,276,598 | 5,595 | 0.0000 | 1.0000 | 99.29 |
| 5.5 | 506,667,373 | 12,475 | 0.0000 | 1.0000 | 99.29 |
| 6.5 | 498,777,926 | 216,145 | 0.0004 | 0.9996 | 99.29 |
| 7.5 | 479,754,779 | 48,151 | 0.0001 | 0.9999 | 99.25 |
| 8.5 | 473,369,886 | 30,168 | 0.0001 | 0.9999 | 99.24 |
| 9.5 | 409,925,508 | 31,833 | 0.0001 | 0.9999 | 99.23 |
| 10.5 | 360,758,863 | 711,383 | 0.0020 | 0.9980 | 99.22 |
| 11.5 | 302,691,784 | 53,581 | 0.0002 | 0.9998 | 99.03 |
| 12.5 | 284,003,764 | 234,944 | 0.0008 | 0.9992 | 99.01 |
| 13.5 | 249,725,580 | 108,802 | 0.0004 | 0.9996 | 98.93 |
| 14.5 | 235,277,562 | 484,974 | 0.0021 | 0.9979 | 98.89 |
| 15.5 | 229,416,384 | 134,039 | 0.0006 | 0.9994 | 98.68 |
| 16.5 | 219,579,972 | 233,186 | 0.0011 | 0.9989 | 98.62 |
| 17.5 | 216,967,480 | 42,089 | 0.0002 | 0.9998 | 98.52 |
| 18.5 | 214,487,385 | 444,882 | 0.0021 | 0.9979 | 98.50 |
| 19.5 | 212,948,140 | 272,415 | 0.0013 | 0.9987 | 98.30 |
| 20.5 | 211,422,628 | 1,317,406 | 0.0062 | 0.9938 | 98.17 |
| 21.5 | 207,073,831 | 157,304 | 0.0008 | 0.9992 | 97.56 |
| 22.5 | 203,282,263 | 479,943 | 0.0024 | 0.9976 | 97.48 |
| 23.5 | 196,935,925 | 269,614 | 0.0014 | 0.9986 | 97.25 |
| 24.5 | 196,619,620 | 184,424 | 0.0009 | 0.9991 | 97.12 |
| 25.5 | 195,371,762 | 37,936 | 0.0002 | 0.9998 | 97.03 |
| 26.5 | 193,050,588 | 1,034,956 | 0.0054 | 0.9946 | 97.01 |
| 27.5 | 189,266,752 | 99,289 | 0.0005 | 0.9995 | 96.49 |
| 28.5 | 184,452,773 | 181,689 | 0.0010 | 0.9990 | 96.44 |
| 29.5 | 182,792,004 | 494,384 | 0.0027 | 0.9973 | 96.35 |
| 30.5 | 181,057,753 | 87,626 | 0.0005 | 0.9995 | 96.08 |
| 31.5 | 189,766,758 | 54,646 | 0.0003 | 0.9997 | 96.04 |
| 32.5 | 188,427,727 | 75,043 | 0.0004 | 0.9996 | 96.01 |
| 33.5 | 179,185,259 | 531,616 | 0.0030 | 0.9970 | 95.97 |
| 34.5 | 174,265,363 | 283,381 | 0.0016 | 0.9984 | 95.69 |
| 35.5 | 92,304,587 | 6,124 | 0.0001 | 0.9999 | 95.53 |
| 36.5 | 89,274,190 | 58,230 | 0.0007 | 0.9993 | 95.53 |
| 37.5 | 84,021,032 | 123,780 | 0.0015 | 0.9985 | 95.46 |
| 38.5 | 77,234,830 | 66,274 | 0.0009 | 0.9991 | 95.32 |

DUKE ENERGY PROGRESS

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 73,403,601 | 91,211 | 0.0012 | 0.9988 | 95.24 |
| 40.5 | 72,924,255 | 484,171 | 0.0066 | 0.9934 | 95.12 |
| 41.5 | 56,036,848 | 326,921 | 0.0058 | 0.9942 | 94.49 |
| 42.5 | 53,692,363 | 37,379 | 0.0007 | 0.9993 | 93.94 |
| 43.5 | 45,005,588 | 47,204 | 0.0010 | 0.9990 | 93.87 |
| 44.5 | 44,907,513 | 1,306,311 | 0.0291 | 0.9709 | 93.78 |
| 45.5 | 33,809,644 | 104,692 | 0.0031 | 0.9969 | 91.05 |
| 46.5 | 33,668,877 | 74,746 | 0.0022 | 0.9978 | 90.77 |
| 47.5 | 31,711,146 | 86,196 | 0.0027 | 0.9973 | 90.56 |
| 48.5 | 31,608,155 | 108,760 | 0.0034 | 0.9966 | 90.32 |
| 49.5 | 31,257,237 | 17,361 | 0.0006 | 0.9994 | 90.01 |
| 50.5 | 27,306,853 | 8,676 | 0.0003 | 0.9997 | 89.96 |
| 51.5 | 27,271,223 | 94,736 | 0.0035 | 0.9965 | 89.93 |
| 52.5 | 17,795,448 | 17,684 | 0.0010 | 0.9990 | 89.62 |
| 53.5 | 16,041,918 | 73,158 | 0.0046 | 0.9954 | 89.53 |
| 54.5 | 13,111,939 | | 0.0000 | 1.0000 | 89.12 |
| 55.5 | 13,111,655 | 581 | 0.0000 | 1.0000 | 89.12 |
| 56.5 | 11,165,020 | 13,232 | 0.0012 | 0.9988 | 89.12 |
| 57.5 | 11,151,408 | | 0.0000 | 1.0000 | 89.01 |
| 58.5 | 10,538,520 | | 0.0000 | 1.0000 | 89.01 |
| 59.5 | 8,185,732 | | 0.0000 | 1.0000 | 89.01 |
| 60.5 | 8,170,007 | 23,840 | 0.0029 | 0.9971 | 89.01 |
| 61.5 | 4,869,879 | | 0.0000 | 1.0000 | 88.75 |
| 62.5 | 1,874,853 | | 0.0000 | 1.0000 | 88.75 |
| 63.5 | 1,855,379 | | 0.0000 | 1.0000 | 88.75 |
| 64.5 | 1,855,379 | | 0.0000 | 1.0000 | 88.75 |
| 65.5 | 1,758,000 | | 0.0000 | 1.0000 | 88.75 |
| 66.5 | 1,756,842 | | 0.0000 | 1.0000 | 88.75 |
| 67.5 | 1,755,584 | | 0.0000 | 1.0000 | 88.75 |
| 68.5 | 1,754,297 | | 0.0000 | 1.0000 | 88.75 |
| 69.5 | 1,753,089 | | 0.0000 | 1.0000 | 88.75 |
| 70.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 71.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 72.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 73.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 74.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 75.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 76.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 77.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |
| 78.5 | 969,792 | | 0.0000 | 1.0000 | 88.75 |

DUKE ENERGY PROGRESS

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 969,792 | 5,407 | 0.0056 | 0.9944 | 88.75 |
| 80.5 | 964,385 | | 0.0000 | 1.0000 | 88.26 |
| 81.5 | 964,385 | | 0.0000 | 1.0000 | 88.26 |
| 82.5 | 964,385 | | 0.0000 | 1.0000 | 88.26 |
| 83.5 | 964,385 | 1,114 | 0.0012 | 0.9988 | 88.26 |
| 84.5 | 963,271 | | 0.0000 | 1.0000 | 88.15 |
| 85.5 | 959,030 | | 0.0000 | 1.0000 | 88.15 |
| 86.5 | 855,131 | | 0.0000 | 1.0000 | 88.15 |
| 87.5 | 855,131 | | 0.0000 | 1.0000 | 88.15 |
| 88.5 | 507,067 | | 0.0000 | 1.0000 | 88.15 |
| 89.5 | | | | | 88.15 |

DUKE ENERGY PROGRESS

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 520,218,535 | 29,135 | 0.0001 | 0.9999 | 100.00 |
| 0.5 | 495,564,670 | 2,297 | 0.0000 | 1.0000 | 99.99 |
| 1.5 | 482,780,222 | 1,893,370 | 0.0039 | 0.9961 | 99.99 |
| 2.5 | 470,852,347 | 918,760 | 0.0020 | 0.9980 | 99.60 |
| 3.5 | 453,801,618 | 962,881 | 0.0021 | 0.9979 | 99.41 |
| 4.5 | 420,920,526 | 47 | 0.0000 | 1.0000 | 99.20 |
| 5.5 | 460,994,196 | 5,103 | 0.0000 | 1.0000 | 99.20 |
| 6.5 | 466,832,866 | 216,070 | 0.0005 | 0.9995 | 99.20 |
| 7.5 | 449,103,818 | 9,260 | 0.0000 | 1.0000 | 99.15 |
| 8.5 | 443,132,945 | 27,276 | 0.0001 | 0.9999 | 99.15 |
| 9.5 | 379,711,798 | 20,025 | 0.0001 | 0.9999 | 99.14 |
| 10.5 | 332,358,489 | 697,449 | 0.0021 | 0.9979 | 99.14 |
| 11.5 | 274,316,424 | 53,366 | 0.0002 | 0.9998 | 98.93 |
| 12.5 | 260,775,803 | 215,807 | 0.0008 | 0.9992 | 98.91 |
| 13.5 | 226,524,543 | 108,444 | 0.0005 | 0.9995 | 98.83 |
| 14.5 | 214,382,342 | 483,735 | 0.0023 | 0.9977 | 98.78 |
| 15.5 | 208,767,502 | 132,339 | 0.0006 | 0.9994 | 98.56 |
| 16.5 | 202,149,365 | 232,886 | 0.0012 | 0.9988 | 98.49 |
| 17.5 | 199,583,052 | 41,039 | 0.0002 | 0.9998 | 98.38 |
| 18.5 | 200,689,601 | 437,792 | 0.0022 | 0.9978 | 98.36 |
| 19.5 | 199,243,443 | 267,533 | 0.0013 | 0.9987 | 98.15 |
| 20.5 | 198,612,666 | 1,295,453 | 0.0065 | 0.9935 | 98.01 |
| 21.5 | 194,286,253 | 155,622 | 0.0008 | 0.9992 | 97.37 |
| 22.5 | 191,974,823 | 473,030 | 0.0025 | 0.9975 | 97.30 |
| 23.5 | 186,543,429 | 227,297 | 0.0012 | 0.9988 | 97.06 |
| 24.5 | 187,555,805 | 183,711 | 0.0010 | 0.9990 | 96.94 |
| 25.5 | 186,497,157 | 37,520 | 0.0002 | 0.9998 | 96.84 |
| 26.5 | 185,381,429 | 1,034,765 | 0.0056 | 0.9944 | 96.82 |
| 27.5 | 184,114,574 | 99,289 | 0.0005 | 0.9995 | 96.28 |
| 28.5 | 179,356,165 | 179,689 | 0.0010 | 0.9990 | 96.23 |
| 29.5 | 180,826,513 | 482,384 | 0.0027 | 0.9973 | 96.14 |
| 30.5 | 179,104,262 | 87,626 | 0.0005 | 0.9995 | 95.88 |
| 31.5 | 187,910,645 | 53,386 | 0.0003 | 0.9997 | 95.83 |
| 32.5 | 186,574,032 | 66,946 | 0.0004 | 0.9996 | 95.81 |
| 33.5 | 177,340,920 | 525,616 | 0.0030 | 0.9970 | 95.77 |
| 34.5 | 172,428,310 | 231,032 | 0.0013 | 0.9987 | 95.49 |
| 35.5 | 90,521,092 | 2,124 | 0.0000 | 1.0000 | 95.36 |
| 36.5 | 88,280,467 | 58,230 | 0.0007 | 0.9993 | 95.36 |
| 37.5 | 83,027,309 | 120,780 | 0.0015 | 0.9985 | 95.29 |
| 38.5 | 76,244,107 | 63,274 | 0.0008 | 0.9992 | 95.16 |

DUKE ENERGY PROGRESS

ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 72,415,878 | 85,861 | 0.0012 | 0.9988 | 95.08 |
| 40.5 | 71,941,882 | 481,171 | 0.0067 | 0.9933 | 94.96 |
| 41.5 | 55,057,475 | 321,821 | 0.0058 | 0.9942 | 94.33 |
| 42.5 | 52,718,091 | 33,298 | 0.0006 | 0.9994 | 93.78 |
| 43.5 | 44,035,396 | 46,804 | 0.0011 | 0.9989 | 93.72 |
| 44.5 | 43,937,721 | 1,306,311 | 0.0297 | 0.9703 | 93.62 |
| 45.5 | 32,839,852 | 104,692 | 0.0032 | 0.9968 | 90.83 |
| 46.5 | 32,699,085 | 74,746 | 0.0023 | 0.9977 | 90.55 |
| 47.5 | 30,741,354 | 86,196 | 0.0028 | 0.9972 | 90.34 |
| 48.5 | 30,638,363 | 108,760 | 0.0035 | 0.9965 | 90.08 |
| 49.5 | 30,287,445 | 17,361 | 0.0006 | 0.9994 | 89.77 |
| 50.5 | 26,337,061 | 8,676 | 0.0003 | 0.9997 | 89.71 |
| 51.5 | 26,306,786 | 94,736 | 0.0036 | 0.9964 | 89.68 |
| 52.5 | 16,934,910 | 17,684 | 0.0010 | 0.9990 | 89.36 |
| 53.5 | 15,181,380 | 73,158 | 0.0048 | 0.9952 | 89.27 |
| 54.5 | 12,599,465 | | 0.0000 | 1.0000 | 88.84 |
| 55.5 | 13,111,655 | 581 | 0.0000 | 1.0000 | 88.84 |
| 56.5 | 11,165,020 | 13,232 | 0.0012 | 0.9988 | 88.83 |
| 57.5 | 11,151,408 | | 0.0000 | 1.0000 | 88.73 |
| 58.5 | 10,538,520 | | 0.0000 | 1.0000 | 88.73 |
| 59.5 | 8,185,732 | | 0.0000 | 1.0000 | 88.73 |
| 60.5 | 8,170,007 | 23,840 | 0.0029 | 0.9971 | 88.73 |
| 61.5 | 4,869,879 | | 0.0000 | 1.0000 | 88.47 |
| 62.5 | 1,874,853 | | 0.0000 | 1.0000 | 88.47 |
| 63.5 | 1,855,379 | | 0.0000 | 1.0000 | 88.47 |
| 64.5 | 1,855,379 | | 0.0000 | 1.0000 | 88.47 |
| 65.5 | 1,758,000 | | 0.0000 | 1.0000 | 88.47 |
| 66.5 | 1,756,842 | | 0.0000 | 1.0000 | 88.47 |
| 67.5 | 1,755,584 | | 0.0000 | 1.0000 | 88.47 |
| 68.5 | 1,754,297 | | 0.0000 | 1.0000 | 88.47 |
| 69.5 | 1,753,089 | | 0.0000 | 1.0000 | 88.47 |
| 70.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 71.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 72.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 73.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 74.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 75.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 76.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 77.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |
| 78.5 | 969,792 | | 0.0000 | 1.0000 | 88.47 |

DUKE ENERGY PROGRESS

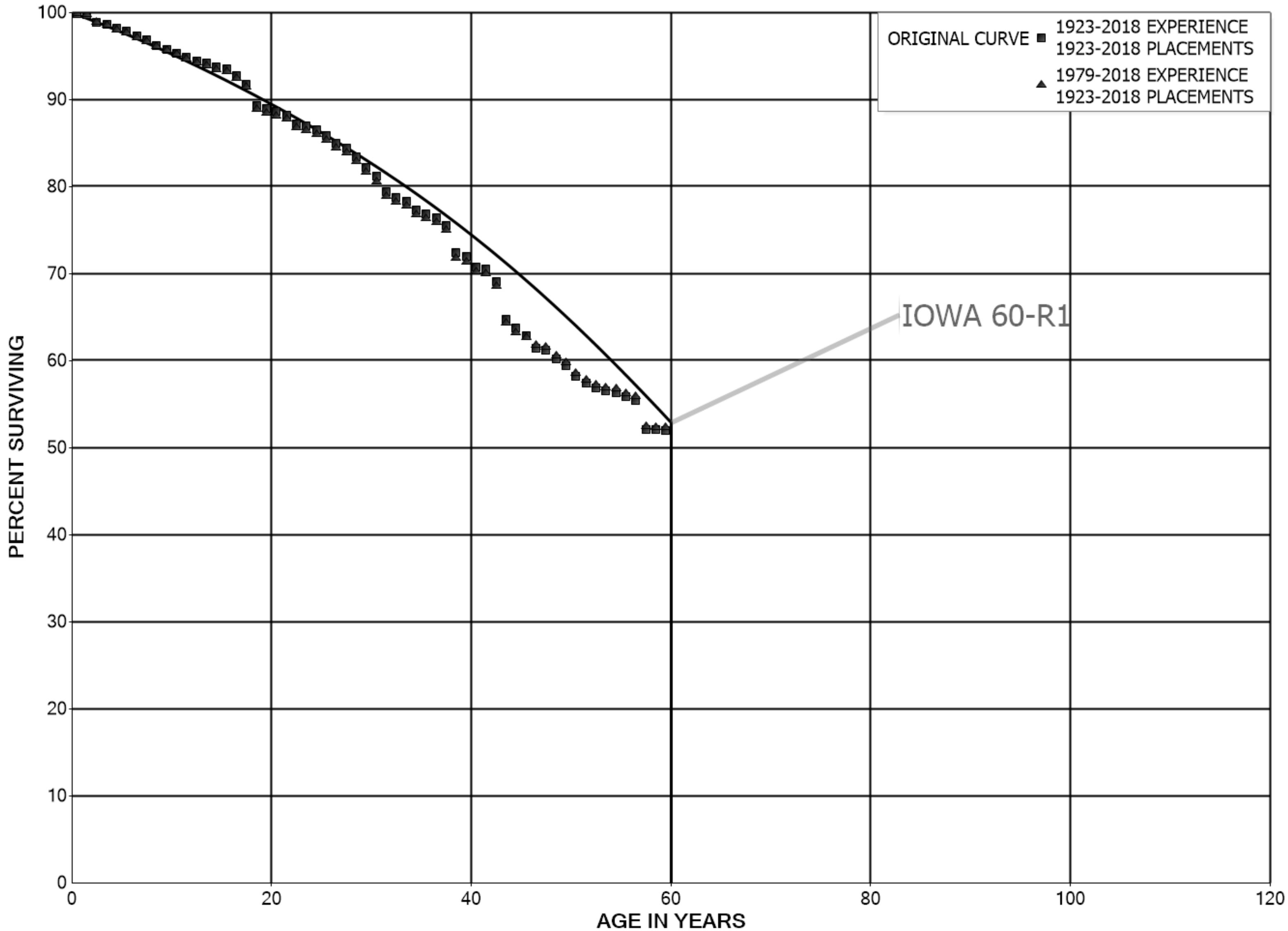
ACCOUNT 311 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 969,792 | 5,407 | 0.0056 | 0.9944 | 88.47 |
| 80.5 | 964,385 | | 0.0000 | 1.0000 | 87.98 |
| 81.5 | 964,385 | | 0.0000 | 1.0000 | 87.98 |
| 82.5 | 964,385 | | 0.0000 | 1.0000 | 87.98 |
| 83.5 | 964,385 | 1,114 | 0.0012 | 0.9988 | 87.98 |
| 84.5 | 963,271 | | 0.0000 | 1.0000 | 87.87 |
| 85.5 | 959,030 | | 0.0000 | 1.0000 | 87.87 |
| 86.5 | 855,131 | | 0.0000 | 1.0000 | 87.87 |
| 87.5 | 855,131 | | 0.0000 | 1.0000 | 87.87 |
| 88.5 | 507,067 | | 0.0000 | 1.0000 | 87.87 |
| 89.5 | | | | | 87.87 |

DUKE ENERGY PROGRESS
ACCOUNT 312 BOILER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 3,301,056,703 | 5,381,641 | 0.0016 | 0.9984 | 100.00 |
| 0.5 | 3,122,918,827 | 3,509,730 | 0.0011 | 0.9989 | 99.84 |
| 1.5 | 3,067,413,402 | 27,055,293 | 0.0088 | 0.9912 | 99.72 |
| 2.5 | 2,985,571,660 | 8,550,863 | 0.0029 | 0.9971 | 98.85 |
| 3.5 | 2,859,270,133 | 12,547,157 | 0.0044 | 0.9956 | 98.56 |
| 4.5 | 2,647,235,532 | 9,146,141 | 0.0035 | 0.9965 | 98.13 |
| 5.5 | 2,538,435,605 | 14,049,255 | 0.0055 | 0.9945 | 97.79 |
| 6.5 | 2,471,200,753 | 10,822,545 | 0.0044 | 0.9956 | 97.25 |
| 7.5 | 2,379,098,035 | 14,755,594 | 0.0062 | 0.9938 | 96.82 |
| 8.5 | 2,299,069,755 | 11,044,088 | 0.0048 | 0.9952 | 96.22 |
| 9.5 | 2,050,213,252 | 9,280,042 | 0.0045 | 0.9955 | 95.76 |
| 10.5 | 1,881,806,462 | 10,252,536 | 0.0054 | 0.9946 | 95.33 |
| 11.5 | 1,521,670,220 | 5,768,483 | 0.0038 | 0.9962 | 94.81 |
| 12.5 | 1,412,298,332 | 4,600,154 | 0.0033 | 0.9967 | 94.45 |
| 13.5 | 1,252,031,844 | 6,122,648 | 0.0049 | 0.9951 | 94.14 |
| 14.5 | 1,190,668,297 | 2,723,306 | 0.0023 | 0.9977 | 93.68 |
| 15.5 | 1,079,492,544 | 8,111,070 | 0.0075 | 0.9925 | 93.47 |
| 16.5 | 1,028,145,353 | 11,373,486 | 0.0111 | 0.9889 | 92.76 |
| 17.5 | 956,107,102 | 25,207,576 | 0.0264 | 0.9736 | 91.74 |
| 18.5 | 890,819,455 | 4,150,378 | 0.0047 | 0.9953 | 89.32 |
| 19.5 | 848,421,742 | 3,006,659 | 0.0035 | 0.9965 | 88.90 |
| 20.5 | 818,064,140 | 3,645,365 | 0.0045 | 0.9955 | 88.59 |
| 21.5 | 787,173,234 | 8,692,262 | 0.0110 | 0.9890 | 88.19 |
| 22.5 | 754,249,638 | 2,689,464 | 0.0036 | 0.9964 | 87.22 |
| 23.5 | 734,049,651 | 3,549,526 | 0.0048 | 0.9952 | 86.91 |
| 24.5 | 719,832,673 | 5,688,798 | 0.0079 | 0.9921 | 86.49 |
| 25.5 | 695,198,414 | 6,746,528 | 0.0097 | 0.9903 | 85.80 |
| 26.5 | 682,738,146 | 5,061,381 | 0.0074 | 0.9926 | 84.97 |
| 27.5 | 672,401,843 | 7,261,439 | 0.0108 | 0.9892 | 84.34 |
| 28.5 | 655,654,672 | 9,923,536 | 0.0151 | 0.9849 | 83.43 |
| 29.5 | 619,386,607 | 7,805,205 | 0.0126 | 0.9874 | 82.17 |
| 30.5 | 609,872,463 | 12,999,101 | 0.0213 | 0.9787 | 81.13 |
| 31.5 | 636,239,579 | 5,058,093 | 0.0079 | 0.9921 | 79.40 |
| 32.5 | 628,060,927 | 4,186,487 | 0.0067 | 0.9933 | 78.77 |
| 33.5 | 619,775,734 | 7,440,463 | 0.0120 | 0.9880 | 78.25 |
| 34.5 | 620,125,164 | 3,493,781 | 0.0056 | 0.9944 | 77.31 |
| 35.5 | 374,481,936 | 2,309,829 | 0.0062 | 0.9938 | 76.87 |
| 36.5 | 358,959,329 | 3,973,554 | 0.0111 | 0.9889 | 76.40 |
| 37.5 | 348,877,992 | 14,796,273 | 0.0424 | 0.9576 | 75.55 |
| 38.5 | 232,819,970 | 1,382,196 | 0.0059 | 0.9941 | 72.35 |

DUKE ENERGY PROGRESS

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 218,798,898 | 3,504,044 | 0.0160 | 0.9840 | 71.92 |
| 40.5 | 209,131,725 | 715,443 | 0.0034 | 0.9966 | 70.77 |
| 41.5 | 179,262,691 | 3,668,953 | 0.0205 | 0.9795 | 70.52 |
| 42.5 | 175,386,209 | 11,022,410 | 0.0628 | 0.9372 | 69.08 |
| 43.5 | 163,662,954 | 2,588,726 | 0.0158 | 0.9842 | 64.74 |
| 44.5 | 154,892,646 | 2,093,791 | 0.0135 | 0.9865 | 63.72 |
| 45.5 | 112,472,826 | 2,582,699 | 0.0230 | 0.9770 | 62.85 |
| 46.5 | 109,739,805 | 395,719 | 0.0036 | 0.9964 | 61.41 |
| 47.5 | 96,062,042 | 1,533,538 | 0.0160 | 0.9840 | 61.19 |
| 48.5 | 94,463,069 | 1,301,956 | 0.0138 | 0.9862 | 60.21 |
| 49.5 | 93,104,121 | 1,849,028 | 0.0199 | 0.9801 | 59.38 |
| 50.5 | 65,549,254 | 851,793 | 0.0130 | 0.9870 | 58.20 |
| 51.5 | 64,661,935 | 636,484 | 0.0098 | 0.9902 | 57.45 |
| 52.5 | 45,291,183 | 277,289 | 0.0061 | 0.9939 | 56.88 |
| 53.5 | 43,125,980 | 162,920 | 0.0038 | 0.9962 | 56.53 |
| 54.5 | 32,740,070 | 294,663 | 0.0090 | 0.9910 | 56.32 |
| 55.5 | 32,714,929 | 214,505 | 0.0066 | 0.9934 | 55.81 |
| 56.5 | 26,113,927 | 1,575,530 | 0.0603 | 0.9397 | 55.45 |
| 57.5 | 24,465,554 | 40,801 | 0.0017 | 0.9983 | 52.10 |
| 58.5 | 19,591,405 | 25,039 | 0.0013 | 0.9987 | 52.02 |
| 59.5 | 11,954,916 | 33,067 | 0.0028 | 0.9972 | 51.95 |
| 60.5 | 8,899,120 | 110,293 | 0.0124 | 0.9876 | 51.80 |
| 61.5 | 4,311,860 | 275,565 | 0.0639 | 0.9361 | 51.16 |
| 62.5 | 1,642,087 | 60,577 | 0.0369 | 0.9631 | 47.89 |
| 63.5 | 1,577,356 | | 0.0000 | 1.0000 | 46.13 |
| 64.5 | 1,575,356 | 226 | 0.0001 | 0.9999 | 46.13 |
| 65.5 | 1,574,890 | | 0.0000 | 1.0000 | 46.12 |
| 66.5 | 1,574,886 | | 0.0000 | 1.0000 | 46.12 |
| 67.5 | 1,574,526 | | 0.0000 | 1.0000 | 46.12 |
| 68.5 | 1,573,626 | | 0.0000 | 1.0000 | 46.12 |
| 69.5 | 864,151 | | 0.0000 | 1.0000 | 46.12 |
| 70.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 71.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 72.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 73.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 74.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 75.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 76.5 | 123,202 | | 0.0000 | 1.0000 | 46.12 |
| 77.5 | 123,202 | 99 | 0.0008 | 0.9992 | 46.12 |
| 78.5 | 123,103 | | 0.0000 | 1.0000 | 46.08 |

DUKE ENERGY PROGRESS

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 123,103 | | 0.0000 | 1.0000 | 46.08 |
| 80.5 | 123,103 | 66,120 | 0.5371 | 0.4629 | 46.08 |
| 81.5 | 56,983 | | 0.0000 | 1.0000 | 21.33 |
| 82.5 | 56,983 | | 0.0000 | 1.0000 | 21.33 |
| 83.5 | 56,983 | 7,742 | 0.1359 | 0.8641 | 21.33 |
| 84.5 | 49,241 | 1,183 | 0.0240 | 0.9760 | 18.43 |
| 85.5 | 48,058 | | 0.0000 | 1.0000 | 17.99 |
| 86.5 | 48,058 | | 0.0000 | 1.0000 | 17.99 |
| 87.5 | 48,058 | 47,658 | 0.9917 | 0.0083 | 17.99 |
| 88.5 | 306 | | 0.0000 | 1.0000 | 0.15 |
| 89.5 | | | | | 0.15 |

DUKE ENERGY PROGRESS

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 2,994,280,719 | 5,182,433 | 0.0017 | 0.9983 | 100.00 |
| 0.5 | 2,820,687,031 | 2,605,605 | 0.0009 | 0.9991 | 99.83 |
| 1.5 | 2,771,043,619 | 26,440,177 | 0.0095 | 0.9905 | 99.73 |
| 2.5 | 2,690,800,862 | 8,476,649 | 0.0032 | 0.9968 | 98.78 |
| 3.5 | 2,582,974,724 | 12,489,502 | 0.0048 | 0.9952 | 98.47 |
| 4.5 | 2,387,111,571 | 9,120,330 | 0.0038 | 0.9962 | 98.00 |
| 5.5 | 2,349,816,850 | 12,688,806 | 0.0054 | 0.9946 | 97.62 |
| 6.5 | 2,317,861,577 | 10,543,313 | 0.0045 | 0.9955 | 97.09 |
| 7.5 | 2,244,879,642 | 13,928,280 | 0.0062 | 0.9938 | 96.65 |
| 8.5 | 2,165,957,870 | 10,985,282 | 0.0051 | 0.9949 | 96.05 |
| 9.5 | 1,917,348,756 | 8,927,773 | 0.0047 | 0.9953 | 95.57 |
| 10.5 | 1,781,303,910 | 10,149,650 | 0.0057 | 0.9943 | 95.12 |
| 11.5 | 1,421,473,844 | 5,713,360 | 0.0040 | 0.9960 | 94.58 |
| 12.5 | 1,329,704,214 | 4,583,647 | 0.0034 | 0.9966 | 94.20 |
| 13.5 | 1,169,518,760 | 5,983,238 | 0.0051 | 0.9949 | 93.87 |
| 14.5 | 1,119,530,794 | 2,491,193 | 0.0022 | 0.9978 | 93.39 |
| 15.5 | 1,008,818,594 | 8,109,304 | 0.0080 | 0.9920 | 93.19 |
| 16.5 | 969,844,459 | 11,177,537 | 0.0115 | 0.9885 | 92.44 |
| 17.5 | 898,061,401 | 25,022,348 | 0.0279 | 0.9721 | 91.37 |
| 18.5 | 843,715,276 | 4,051,068 | 0.0048 | 0.9952 | 88.83 |
| 19.5 | 802,914,944 | 2,779,515 | 0.0035 | 0.9965 | 88.40 |
| 20.5 | 778,213,682 | 3,468,677 | 0.0045 | 0.9955 | 88.09 |
| 21.5 | 747,512,093 | 8,657,400 | 0.0116 | 0.9884 | 87.70 |
| 22.5 | 721,959,869 | 2,499,697 | 0.0035 | 0.9965 | 86.68 |
| 23.5 | 707,445,383 | 3,475,822 | 0.0049 | 0.9951 | 86.38 |
| 24.5 | 698,354,580 | 5,662,564 | 0.0081 | 0.9919 | 85.96 |
| 25.5 | 673,915,236 | 6,668,823 | 0.0099 | 0.9901 | 85.26 |
| 26.5 | 668,451,591 | 5,030,638 | 0.0075 | 0.9925 | 84.42 |
| 27.5 | 661,885,422 | 7,247,083 | 0.0109 | 0.9891 | 83.78 |
| 28.5 | 647,161,760 | 9,923,536 | 0.0153 | 0.9847 | 82.87 |
| 29.5 | 613,940,336 | 7,798,497 | 0.0127 | 0.9873 | 81.60 |
| 30.5 | 604,434,900 | 12,999,101 | 0.0215 | 0.9785 | 80.56 |
| 31.5 | 630,802,429 | 4,979,611 | 0.0079 | 0.9921 | 78.83 |
| 32.5 | 622,702,489 | 4,162,885 | 0.0067 | 0.9933 | 78.20 |
| 33.5 | 614,441,258 | 7,440,463 | 0.0121 | 0.9879 | 77.68 |
| 34.5 | 614,791,588 | 3,493,781 | 0.0057 | 0.9943 | 76.74 |
| 35.5 | 369,983,607 | 2,309,829 | 0.0062 | 0.9938 | 76.31 |
| 36.5 | 355,411,908 | 3,973,554 | 0.0112 | 0.9888 | 75.83 |
| 37.5 | 345,330,571 | 14,796,273 | 0.0428 | 0.9572 | 74.98 |
| 38.5 | 229,272,549 | 1,382,196 | 0.0060 | 0.9940 | 71.77 |

DUKE ENERGY PROGRESS

ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 215,251,476 | 3,504,044 | 0.0163 | 0.9837 | 71.34 |
| 40.5 | 205,584,304 | 715,443 | 0.0035 | 0.9965 | 70.17 |
| 41.5 | 175,715,270 | 3,668,953 | 0.0209 | 0.9791 | 69.93 |
| 42.5 | 171,838,788 | 10,622,410 | 0.0618 | 0.9382 | 68.47 |
| 43.5 | 160,515,532 | 2,588,726 | 0.0161 | 0.9839 | 64.24 |
| 44.5 | 151,745,225 | 1,493,791 | 0.0098 | 0.9902 | 63.20 |
| 45.5 | 109,925,405 | 1,441,281 | 0.0131 | 0.9869 | 62.58 |
| 46.5 | 108,333,802 | 395,719 | 0.0037 | 0.9963 | 61.76 |
| 47.5 | 94,656,039 | 1,533,538 | 0.0162 | 0.9838 | 61.53 |
| 48.5 | 93,057,066 | 1,301,956 | 0.0140 | 0.9860 | 60.54 |
| 49.5 | 91,698,118 | 1,849,028 | 0.0202 | 0.9798 | 59.69 |
| 50.5 | 64,143,250 | 819,163 | 0.0128 | 0.9872 | 58.49 |
| 51.5 | 63,296,304 | 636,484 | 0.0101 | 0.9899 | 57.74 |
| 52.5 | 43,926,834 | 277,289 | 0.0063 | 0.9937 | 57.16 |
| 53.5 | 41,761,631 | 84,940 | 0.0020 | 0.9980 | 56.80 |
| 54.5 | 31,453,795 | 292,317 | 0.0093 | 0.9907 | 56.68 |
| 55.5 | 32,714,929 | 214,505 | 0.0066 | 0.9934 | 56.16 |
| 56.5 | 26,113,927 | 1,575,530 | 0.0603 | 0.9397 | 55.79 |
| 57.5 | 24,465,554 | 40,801 | 0.0017 | 0.9983 | 52.42 |
| 58.5 | 19,591,405 | 25,039 | 0.0013 | 0.9987 | 52.33 |
| 59.5 | 11,954,916 | 33,067 | 0.0028 | 0.9972 | 52.27 |
| 60.5 | 8,899,120 | 110,293 | 0.0124 | 0.9876 | 52.12 |
| 61.5 | 4,311,860 | 275,565 | 0.0639 | 0.9361 | 51.48 |
| 62.5 | 1,642,087 | 60,577 | 0.0369 | 0.9631 | 48.19 |
| 63.5 | 1,577,356 | | 0.0000 | 1.0000 | 46.41 |
| 64.5 | 1,575,356 | 226 | 0.0001 | 0.9999 | 46.41 |
| 65.5 | 1,574,890 | | 0.0000 | 1.0000 | 46.40 |
| 66.5 | 1,574,886 | | 0.0000 | 1.0000 | 46.40 |
| 67.5 | 1,574,526 | | 0.0000 | 1.0000 | 46.40 |
| 68.5 | 1,573,626 | | 0.0000 | 1.0000 | 46.40 |
| 69.5 | 864,151 | | 0.0000 | 1.0000 | 46.40 |
| 70.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 71.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 72.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 73.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 74.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 75.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 76.5 | 123,202 | | 0.0000 | 1.0000 | 46.40 |
| 77.5 | 123,202 | 99 | 0.0008 | 0.9992 | 46.40 |
| 78.5 | 123,103 | | 0.0000 | 1.0000 | 46.37 |

DUKE ENERGY PROGRESS

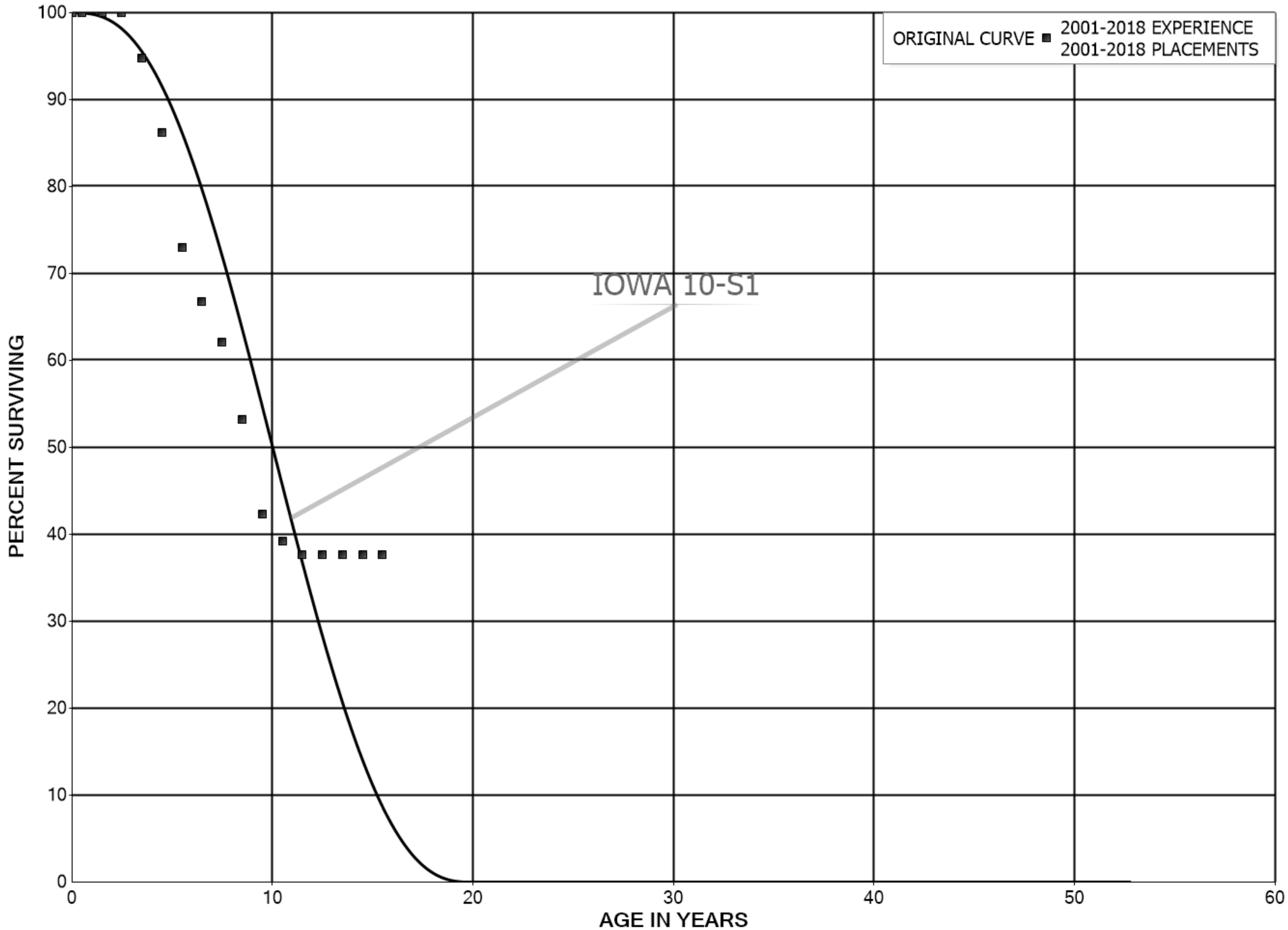
ACCOUNT 312 BOILER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 123,103 | | 0.0000 | 1.0000 | 46.37 |
| 80.5 | 123,103 | 66,120 | 0.5371 | 0.4629 | 46.37 |
| 81.5 | 56,983 | | 0.0000 | 1.0000 | 21.46 |
| 82.5 | 56,983 | | 0.0000 | 1.0000 | 21.46 |
| 83.5 | 56,983 | 7,742 | 0.1359 | 0.8641 | 21.46 |
| 84.5 | 49,241 | 1,183 | 0.0240 | 0.9760 | 18.55 |
| 85.5 | 48,058 | | 0.0000 | 1.0000 | 18.10 |
| 86.5 | 48,058 | | 0.0000 | 1.0000 | 18.10 |
| 87.5 | 48,058 | 47,658 | 0.9917 | 0.0083 | 18.10 |
| 88.5 | 306 | | 0.0000 | 1.0000 | 0.15 |
| 89.5 | | | | | 0.15 |

DUKE ENERGY PROGRESS
ACCOUNT 312.1 BOILER PLANT EQUIPMENT - SCR CATALYST
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

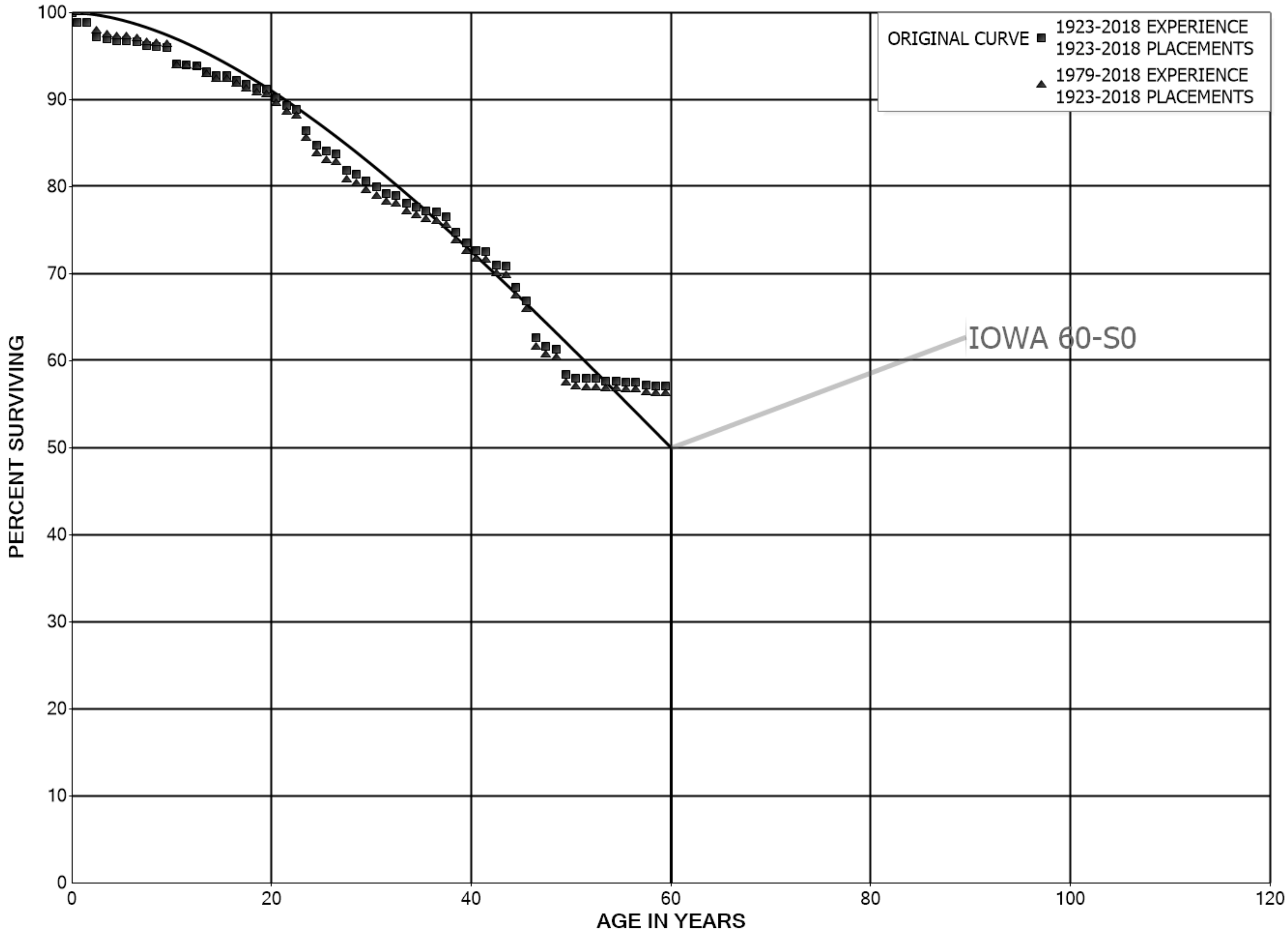
ACCOUNT 312.1 BOILER PLANT EQUIPMENT - SCR CATALYST

ORIGINAL LIFE TABLE

PLACEMENT BAND 2001-2018 EXPERIENCE BAND 2001-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 63,893,747 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 62,833,100 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 65,357,870 | | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 67,377,234 | 3,537,685 | 0.0525 | 0.9475 | 100.00 |
| 3.5 | 68,083,086 | 6,128,287 | 0.0900 | 0.9100 | 94.75 |
| 4.5 | 64,285,703 | 9,931,979 | 0.1545 | 0.8455 | 86.22 |
| 5.5 | 54,854,789 | 4,685,454 | 0.0854 | 0.9146 | 72.90 |
| 6.5 | 48,926,045 | 3,397,424 | 0.0694 | 0.9306 | 66.67 |
| 7.5 | 38,542,637 | 5,526,104 | 0.1434 | 0.8566 | 62.04 |
| 8.5 | 26,790,987 | 5,502,386 | 0.2054 | 0.7946 | 53.15 |
| 9.5 | 13,910,381 | 990,248 | 0.0712 | 0.9288 | 42.23 |
| 10.5 | 10,706,621 | 436,848 | 0.0408 | 0.9592 | 39.23 |
| 11.5 | 5,065,538 | | 0.0000 | 1.0000 | 37.63 |
| 12.5 | 5,065,538 | | 0.0000 | 1.0000 | 37.63 |
| 13.5 | 5,065,538 | | 0.0000 | 1.0000 | 37.63 |
| 14.5 | 5,065,538 | | 0.0000 | 1.0000 | 37.63 |
| 15.5 | | | | | 37.63 |

DUKE ENERGY PROGRESS
ACCOUNT 314 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 572,448,094 | 6,357,231 | 0.0111 | 0.9889 | 100.00 |
| 0.5 | 558,020,048 | 63,284 | 0.0001 | 0.9999 | 98.89 |
| 1.5 | 555,879,066 | 9,340,642 | 0.0168 | 0.9832 | 98.88 |
| 2.5 | 541,995,110 | 1,757,429 | 0.0032 | 0.9968 | 97.22 |
| 3.5 | 492,259,432 | 759,124 | 0.0015 | 0.9985 | 96.90 |
| 4.5 | 459,775,161 | 184,402 | 0.0004 | 0.9996 | 96.75 |
| 5.5 | 422,931,181 | 664,363 | 0.0016 | 0.9984 | 96.71 |
| 6.5 | 411,900,670 | 1,620,726 | 0.0039 | 0.9961 | 96.56 |
| 7.5 | 396,869,780 | 503,138 | 0.0013 | 0.9987 | 96.18 |
| 8.5 | 390,414,409 | 392,996 | 0.0010 | 0.9990 | 96.06 |
| 9.5 | 384,936,354 | 7,723,516 | 0.0201 | 0.9799 | 95.96 |
| 10.5 | 366,047,317 | 184,485 | 0.0005 | 0.9995 | 94.04 |
| 11.5 | 362,371,954 | 414,968 | 0.0011 | 0.9989 | 93.99 |
| 12.5 | 359,936,777 | 2,705,287 | 0.0075 | 0.9925 | 93.88 |
| 13.5 | 355,810,184 | 1,722,892 | 0.0048 | 0.9952 | 93.18 |
| 14.5 | 353,505,552 | 10,477 | 0.0000 | 1.0000 | 92.73 |
| 15.5 | 347,176,903 | 1,873,868 | 0.0054 | 0.9946 | 92.72 |
| 16.5 | 343,677,920 | 1,753,652 | 0.0051 | 0.9949 | 92.22 |
| 17.5 | 340,712,137 | 1,628,787 | 0.0048 | 0.9952 | 91.75 |
| 18.5 | 333,512,497 | 537,274 | 0.0016 | 0.9984 | 91.31 |
| 19.5 | 331,674,205 | 3,453,416 | 0.0104 | 0.9896 | 91.17 |
| 20.5 | 319,811,569 | 3,256,220 | 0.0102 | 0.9898 | 90.22 |
| 21.5 | 309,654,632 | 1,489,048 | 0.0048 | 0.9952 | 89.30 |
| 22.5 | 293,658,338 | 8,140,343 | 0.0277 | 0.9723 | 88.87 |
| 23.5 | 282,756,109 | 5,570,839 | 0.0197 | 0.9803 | 86.41 |
| 24.5 | 273,147,258 | 2,201,588 | 0.0081 | 0.9919 | 84.70 |
| 25.5 | 260,673,001 | 875,801 | 0.0034 | 0.9966 | 84.02 |
| 26.5 | 243,674,352 | 5,544,335 | 0.0228 | 0.9772 | 83.74 |
| 27.5 | 233,888,342 | 1,323,399 | 0.0057 | 0.9943 | 81.83 |
| 28.5 | 228,167,416 | 2,160,368 | 0.0095 | 0.9905 | 81.37 |
| 29.5 | 224,695,286 | 1,871,979 | 0.0083 | 0.9917 | 80.60 |
| 30.5 | 217,716,180 | 1,990,173 | 0.0091 | 0.9909 | 79.93 |
| 31.5 | 225,306,928 | 595,040 | 0.0026 | 0.9974 | 79.20 |
| 32.5 | 222,640,867 | 2,591,604 | 0.0116 | 0.9884 | 78.99 |
| 33.5 | 215,804,933 | 1,253,462 | 0.0058 | 0.9942 | 78.07 |
| 34.5 | 216,627,031 | 1,178,168 | 0.0054 | 0.9946 | 77.62 |
| 35.5 | 146,392,067 | 287,614 | 0.0020 | 0.9980 | 77.19 |
| 36.5 | 143,678,527 | 919,736 | 0.0064 | 0.9936 | 77.04 |
| 37.5 | 139,463,811 | 3,268,718 | 0.0234 | 0.9766 | 76.55 |
| 38.5 | 104,212,242 | 1,691,143 | 0.0162 | 0.9838 | 74.75 |

DUKE ENERGY PROGRESS

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 102,474,794 | 1,262,008 | 0.0123 | 0.9877 | 73.54 |
| 40.5 | 101,164,940 | 108,618 | 0.0011 | 0.9989 | 72.64 |
| 41.5 | 89,973,314 | 1,973,310 | 0.0219 | 0.9781 | 72.56 |
| 42.5 | 84,307,780 | 214,740 | 0.0025 | 0.9975 | 70.97 |
| 43.5 | 84,091,626 | 2,805,775 | 0.0334 | 0.9666 | 70.79 |
| 44.5 | 81,279,966 | 1,837,503 | 0.0226 | 0.9774 | 68.42 |
| 45.5 | 63,520,208 | 4,093,918 | 0.0645 | 0.9355 | 66.88 |
| 46.5 | 59,420,090 | 927,102 | 0.0156 | 0.9844 | 62.57 |
| 47.5 | 53,189,297 | 259,198 | 0.0049 | 0.9951 | 61.59 |
| 48.5 | 52,927,661 | 2,469,912 | 0.0467 | 0.9533 | 61.29 |
| 49.5 | 50,456,796 | 426,204 | 0.0084 | 0.9916 | 58.43 |
| 50.5 | 39,251,897 | 19,133 | 0.0005 | 0.9995 | 57.94 |
| 51.5 | 39,232,511 | | 0.0000 | 1.0000 | 57.91 |
| 52.5 | 30,742,177 | 136,842 | 0.0045 | 0.9955 | 57.91 |
| 53.5 | 28,351,006 | 39,763 | 0.0014 | 0.9986 | 57.65 |
| 54.5 | 20,407,487 | 34,503 | 0.0017 | 0.9983 | 57.57 |
| 55.5 | 20,372,108 | 1,032 | 0.0001 | 0.9999 | 57.47 |
| 56.5 | 16,656,591 | 90,486 | 0.0054 | 0.9946 | 57.47 |
| 57.5 | 16,532,214 | 39,704 | 0.0024 | 0.9976 | 57.16 |
| 58.5 | 13,821,416 | | 0.0000 | 1.0000 | 57.02 |
| 59.5 | 8,871,634 | | 0.0000 | 1.0000 | 57.02 |
| 60.5 | 6,516,720 | | 0.0000 | 1.0000 | 57.02 |
| 61.5 | 3,732,951 | | 0.0000 | 1.0000 | 57.02 |
| 62.5 | 2,275,313 | 1,795 | 0.0008 | 0.9992 | 57.02 |
| 63.5 | 2,273,518 | | 0.0000 | 1.0000 | 56.97 |
| 64.5 | 2,273,518 | 932 | 0.0004 | 0.9996 | 56.97 |
| 65.5 | 2,272,586 | | 0.0000 | 1.0000 | 56.95 |
| 66.5 | 2,272,586 | | 0.0000 | 1.0000 | 56.95 |
| 67.5 | 2,272,586 | | 0.0000 | 1.0000 | 56.95 |
| 68.5 | 2,272,586 | 811 | 0.0004 | 0.9996 | 56.95 |
| 69.5 | 1,596,222 | | 0.0000 | 1.0000 | 56.93 |
| 70.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 71.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 72.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 73.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 74.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 75.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 76.5 | 926,493 | | 0.0000 | 1.0000 | 56.93 |
| 77.5 | 926,493 | 9,328 | 0.0101 | 0.9899 | 56.93 |
| 78.5 | 917,165 | | 0.0000 | 1.0000 | 56.36 |

DUKE ENERGY PROGRESS

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 917,165 | | 0.0000 | 1.0000 | 56.36 |
| 80.5 | 917,165 | | 0.0000 | 1.0000 | 56.36 |
| 81.5 | 917,165 | | 0.0000 | 1.0000 | 56.36 |
| 82.5 | 917,165 | | 0.0000 | 1.0000 | 56.36 |
| 83.5 | 917,165 | 1,232 | 0.0013 | 0.9987 | 56.36 |
| 84.5 | 915,933 | | 0.0000 | 1.0000 | 56.28 |
| 85.5 | 915,933 | | 0.0000 | 1.0000 | 56.28 |
| 86.5 | 914,549 | 401,068 | 0.4385 | 0.5615 | 56.28 |
| 87.5 | 513,481 | 512,134 | 0.9974 | 0.0026 | 31.60 |
| 88.5 | 1,347 | | 0.0000 | 1.0000 | 0.08 |
| 89.5 | | | | | 0.08 |

DUKE ENERGY PROGRESS

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 440,448,186 | 14,607 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 432,366,591 | 32,709 | 0.0001 | 0.9999 | 100.00 |
| 1.5 | 430,830,711 | 9,340,642 | 0.0217 | 0.9783 | 99.99 |
| 2.5 | 422,622,446 | 1,757,429 | 0.0042 | 0.9958 | 97.82 |
| 3.5 | 375,961,368 | 759,105 | 0.0020 | 0.9980 | 97.41 |
| 4.5 | 343,485,759 | 184,402 | 0.0005 | 0.9995 | 97.22 |
| 5.5 | 329,618,979 | 664,363 | 0.0020 | 0.9980 | 97.17 |
| 6.5 | 332,847,355 | 1,620,726 | 0.0049 | 0.9951 | 96.97 |
| 7.5 | 325,806,936 | 503,138 | 0.0015 | 0.9985 | 96.50 |
| 8.5 | 319,421,151 | 392,996 | 0.0012 | 0.9988 | 96.35 |
| 9.5 | 313,943,816 | 7,723,516 | 0.0246 | 0.9754 | 96.23 |
| 10.5 | 302,616,531 | 184,485 | 0.0006 | 0.9994 | 93.86 |
| 11.5 | 298,994,032 | 414,968 | 0.0014 | 0.9986 | 93.81 |
| 12.5 | 304,456,772 | 2,702,287 | 0.0089 | 0.9911 | 93.68 |
| 13.5 | 300,341,734 | 1,717,025 | 0.0057 | 0.9943 | 92.84 |
| 14.5 | 304,046,372 | 6,477 | 0.0000 | 1.0000 | 92.31 |
| 15.5 | 297,735,060 | 1,872,668 | 0.0063 | 0.9937 | 92.31 |
| 16.5 | 303,742,996 | 1,750,302 | 0.0058 | 0.9942 | 91.73 |
| 17.5 | 300,782,814 | 1,628,787 | 0.0054 | 0.9946 | 91.20 |
| 18.5 | 300,917,001 | 526,756 | 0.0018 | 0.9982 | 90.71 |
| 19.5 | 304,409,416 | 3,451,616 | 0.0113 | 0.9887 | 90.55 |
| 20.5 | 297,110,204 | 3,235,158 | 0.0109 | 0.9891 | 89.52 |
| 21.5 | 286,977,487 | 1,489,048 | 0.0052 | 0.9948 | 88.55 |
| 22.5 | 275,713,533 | 8,138,487 | 0.0295 | 0.9705 | 88.09 |
| 23.5 | 268,102,884 | 5,570,839 | 0.0208 | 0.9792 | 85.49 |
| 24.5 | 261,623,635 | 2,201,588 | 0.0084 | 0.9916 | 83.71 |
| 25.5 | 249,149,378 | 875,801 | 0.0035 | 0.9965 | 83.01 |
| 26.5 | 236,849,131 | 5,544,335 | 0.0234 | 0.9766 | 82.72 |
| 27.5 | 229,010,247 | 1,323,399 | 0.0058 | 0.9942 | 80.78 |
| 28.5 | 224,336,039 | 2,160,368 | 0.0096 | 0.9904 | 80.31 |
| 29.5 | 222,349,191 | 1,871,979 | 0.0084 | 0.9916 | 79.54 |
| 30.5 | 215,370,085 | 1,990,173 | 0.0092 | 0.9908 | 78.87 |
| 31.5 | 222,960,833 | 595,040 | 0.0027 | 0.9973 | 78.14 |
| 32.5 | 220,295,704 | 2,591,604 | 0.0118 | 0.9882 | 77.93 |
| 33.5 | 213,459,770 | 1,253,462 | 0.0059 | 0.9941 | 77.02 |
| 34.5 | 214,281,868 | 1,178,168 | 0.0055 | 0.9945 | 76.56 |
| 35.5 | 144,722,457 | 287,614 | 0.0020 | 0.9980 | 76.14 |
| 36.5 | 142,680,440 | 919,736 | 0.0064 | 0.9936 | 75.99 |
| 37.5 | 138,465,725 | 3,268,718 | 0.0236 | 0.9764 | 75.50 |
| 38.5 | 103,214,156 | 1,691,143 | 0.0164 | 0.9836 | 73.72 |

DUKE ENERGY PROGRESS

ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 101,476,708 | 1,262,008 | 0.0124 | 0.9876 | 72.51 |
| 40.5 | 100,166,854 | 108,618 | 0.0011 | 0.9989 | 71.61 |
| 41.5 | 88,975,228 | 1,973,310 | 0.0222 | 0.9778 | 71.53 |
| 42.5 | 83,309,694 | 214,740 | 0.0026 | 0.9974 | 69.94 |
| 43.5 | 83,093,540 | 2,805,775 | 0.0338 | 0.9662 | 69.76 |
| 44.5 | 80,281,880 | 1,837,503 | 0.0229 | 0.9771 | 67.41 |
| 45.5 | 62,522,122 | 4,093,918 | 0.0655 | 0.9345 | 65.87 |
| 46.5 | 58,422,004 | 927,102 | 0.0159 | 0.9841 | 61.55 |
| 47.5 | 52,191,211 | 259,198 | 0.0050 | 0.9950 | 60.58 |
| 48.5 | 51,929,575 | 2,469,912 | 0.0476 | 0.9524 | 60.28 |
| 49.5 | 49,458,710 | 426,204 | 0.0086 | 0.9914 | 57.41 |
| 50.5 | 38,253,811 | 19,133 | 0.0005 | 0.9995 | 56.91 |
| 51.5 | 38,235,657 | | 0.0000 | 1.0000 | 56.89 |
| 52.5 | 29,746,707 | 66,060 | 0.0022 | 0.9978 | 56.89 |
| 53.5 | 27,426,318 | 39,763 | 0.0014 | 0.9986 | 56.76 |
| 54.5 | 19,894,006 | 34,503 | 0.0017 | 0.9983 | 56.68 |
| 55.5 | 20,372,108 | 1,032 | 0.0001 | 0.9999 | 56.58 |
| 56.5 | 16,656,591 | 90,486 | 0.0054 | 0.9946 | 56.58 |
| 57.5 | 16,532,214 | 39,704 | 0.0024 | 0.9976 | 56.27 |
| 58.5 | 13,821,416 | | 0.0000 | 1.0000 | 56.13 |
| 59.5 | 8,871,634 | | 0.0000 | 1.0000 | 56.13 |
| 60.5 | 6,516,720 | | 0.0000 | 1.0000 | 56.13 |
| 61.5 | 3,732,951 | | 0.0000 | 1.0000 | 56.13 |
| 62.5 | 2,275,313 | 1,795 | 0.0008 | 0.9992 | 56.13 |
| 63.5 | 2,273,518 | | 0.0000 | 1.0000 | 56.09 |
| 64.5 | 2,273,518 | 932 | 0.0004 | 0.9996 | 56.09 |
| 65.5 | 2,272,586 | | 0.0000 | 1.0000 | 56.07 |
| 66.5 | 2,272,586 | | 0.0000 | 1.0000 | 56.07 |
| 67.5 | 2,272,586 | | 0.0000 | 1.0000 | 56.07 |
| 68.5 | 2,272,586 | 811 | 0.0004 | 0.9996 | 56.07 |
| 69.5 | 1,596,222 | | 0.0000 | 1.0000 | 56.05 |
| 70.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 71.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 72.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 73.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 74.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 75.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 76.5 | 926,493 | | 0.0000 | 1.0000 | 56.05 |
| 77.5 | 926,493 | 9,328 | 0.0101 | 0.9899 | 56.05 |
| 78.5 | 917,165 | | 0.0000 | 1.0000 | 55.48 |

DUKE ENERGY PROGRESS

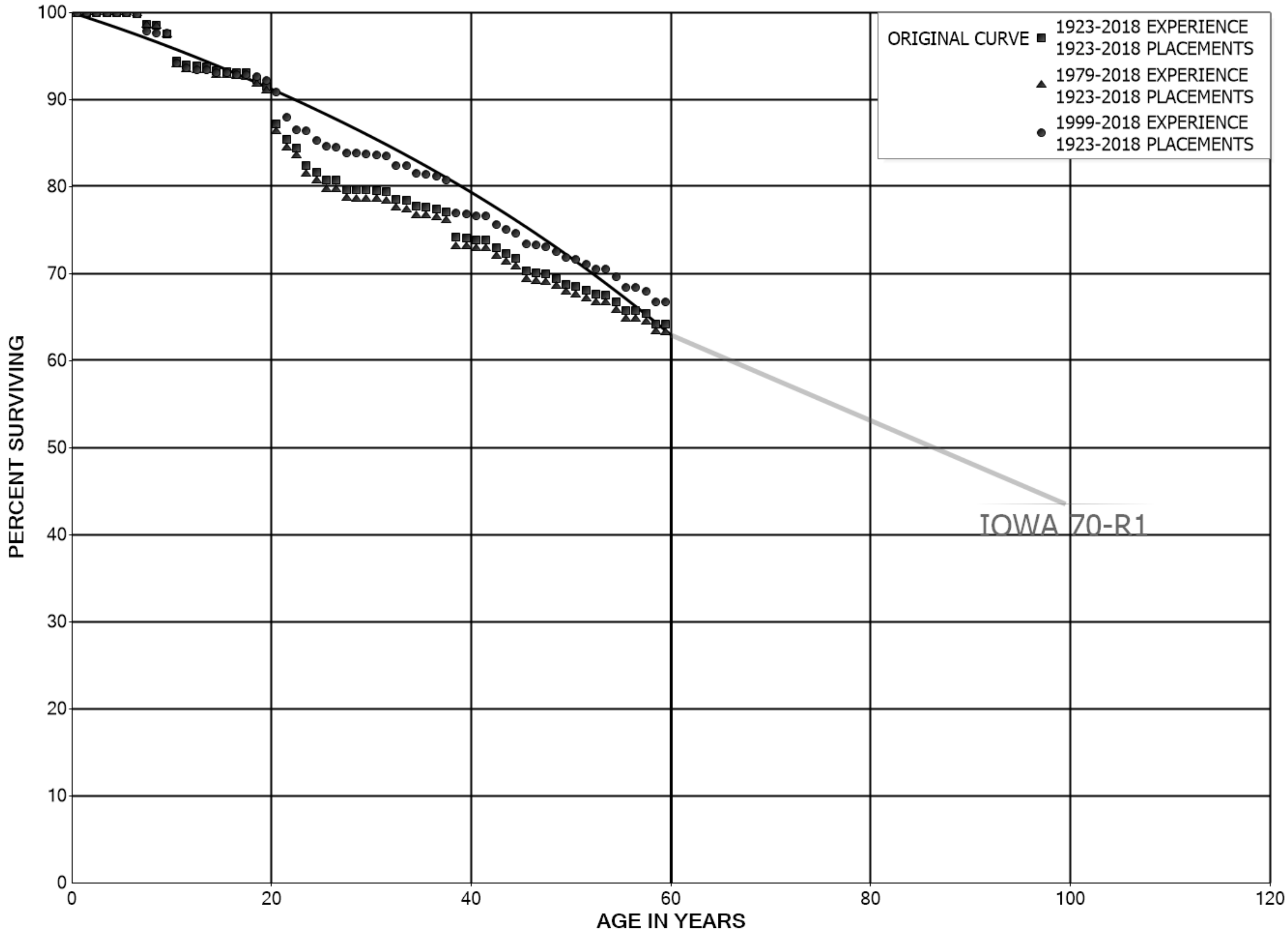
ACCOUNT 314 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 917,165 | | 0.0000 | 1.0000 | 55.48 |
| 80.5 | 917,165 | | 0.0000 | 1.0000 | 55.48 |
| 81.5 | 917,165 | | 0.0000 | 1.0000 | 55.48 |
| 82.5 | 917,165 | | 0.0000 | 1.0000 | 55.48 |
| 83.5 | 917,165 | 1,232 | 0.0013 | 0.9987 | 55.48 |
| 84.5 | 915,933 | | 0.0000 | 1.0000 | 55.41 |
| 85.5 | 915,933 | | 0.0000 | 1.0000 | 55.41 |
| 86.5 | 914,549 | 401,068 | 0.4385 | 0.5615 | 55.41 |
| 87.5 | 513,481 | 512,134 | 0.9974 | 0.0026 | 31.11 |
| 88.5 | 1,347 | | 0.0000 | 1.0000 | 0.08 |
| 89.5 | | | | | 0.08 |

DUKE ENERGY PROGRESS
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 321,142,175 | 3,915 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 311,168,782 | 25,665 | 0.0001 | 0.9999 | 100.00 |
| 1.5 | 309,263,887 | 5,974 | 0.0000 | 1.0000 | 99.99 |
| 2.5 | 301,187,469 | 78,847 | 0.0003 | 0.9997 | 99.99 |
| 3.5 | 282,045,712 | 83,732 | 0.0003 | 0.9997 | 99.96 |
| 4.5 | 274,084,480 | 5,614 | 0.0000 | 1.0000 | 99.93 |
| 5.5 | 272,929,556 | 227,416 | 0.0008 | 0.9992 | 99.93 |
| 6.5 | 271,301,475 | 3,343,809 | 0.0123 | 0.9877 | 99.85 |
| 7.5 | 258,150,628 | 380,698 | 0.0015 | 0.9985 | 98.62 |
| 8.5 | 255,753,537 | 2,416,191 | 0.0094 | 0.9906 | 98.47 |
| 9.5 | 223,003,386 | 7,087,247 | 0.0318 | 0.9682 | 97.54 |
| 10.5 | 190,246,634 | 1,069,716 | 0.0056 | 0.9944 | 94.44 |
| 11.5 | 147,514,028 | 152,906 | 0.0010 | 0.9990 | 93.91 |
| 12.5 | 140,316,012 | 101,865 | 0.0007 | 0.9993 | 93.81 |
| 13.5 | 126,139,041 | 632,085 | 0.0050 | 0.9950 | 93.74 |
| 14.5 | 122,362,668 | 102,403 | 0.0008 | 0.9992 | 93.27 |
| 15.5 | 113,502,858 | 160,152 | 0.0014 | 0.9986 | 93.20 |
| 16.5 | 112,476,995 | 32,894 | 0.0003 | 0.9997 | 93.07 |
| 17.5 | 110,017,180 | 862,864 | 0.0078 | 0.9922 | 93.04 |
| 18.5 | 108,206,157 | 927,214 | 0.0086 | 0.9914 | 92.31 |
| 19.5 | 107,109,734 | 5,074,976 | 0.0474 | 0.9526 | 91.52 |
| 20.5 | 101,131,427 | 2,126,589 | 0.0210 | 0.9790 | 87.18 |
| 21.5 | 97,983,556 | 1,069,667 | 0.0109 | 0.9891 | 85.35 |
| 22.5 | 96,145,986 | 2,318,367 | 0.0241 | 0.9759 | 84.42 |
| 23.5 | 91,038,772 | 808,446 | 0.0089 | 0.9911 | 82.38 |
| 24.5 | 90,160,189 | 1,029,463 | 0.0114 | 0.9886 | 81.65 |
| 25.5 | 88,846,322 | 38,545 | 0.0004 | 0.9996 | 80.72 |
| 26.5 | 87,482,900 | 1,136,766 | 0.0130 | 0.9870 | 80.68 |
| 27.5 | 82,190,867 | 21,312 | 0.0003 | 0.9997 | 79.63 |
| 28.5 | 78,573,751 | 38,358 | 0.0005 | 0.9995 | 79.61 |
| 29.5 | 73,636,124 | 50,461 | 0.0007 | 0.9993 | 79.57 |
| 30.5 | 72,720,447 | 140,598 | 0.0019 | 0.9981 | 79.52 |
| 31.5 | 75,604,272 | 787,710 | 0.0104 | 0.9896 | 79.37 |
| 32.5 | 74,821,613 | 153,261 | 0.0020 | 0.9980 | 78.54 |
| 33.5 | 74,383,331 | 639,830 | 0.0086 | 0.9914 | 78.38 |
| 34.5 | 72,687,914 | 79,638 | 0.0011 | 0.9989 | 77.70 |
| 35.5 | 47,638,914 | 126,568 | 0.0027 | 0.9973 | 77.62 |
| 36.5 | 45,581,566 | 203,816 | 0.0045 | 0.9955 | 77.41 |
| 37.5 | 44,625,046 | 1,703,460 | 0.0382 | 0.9618 | 77.07 |
| 38.5 | 32,102,825 | 34,046 | 0.0011 | 0.9989 | 74.12 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 30,737,198 | 84,140 | 0.0027 | 0.9973 | 74.05 |
| 40.5 | 30,207,208 | 21,706 | 0.0007 | 0.9993 | 73.84 |
| 41.5 | 24,910,927 | 296,200 | 0.0119 | 0.9881 | 73.79 |
| 42.5 | 23,727,467 | 221,096 | 0.0093 | 0.9907 | 72.91 |
| 43.5 | 23,462,309 | 175,718 | 0.0075 | 0.9925 | 72.23 |
| 44.5 | 23,251,018 | 446,014 | 0.0192 | 0.9808 | 71.69 |
| 45.5 | 16,859,931 | 62,590 | 0.0037 | 0.9963 | 70.32 |
| 46.5 | 16,737,309 | 30,244 | 0.0018 | 0.9982 | 70.06 |
| 47.5 | 14,255,593 | 100,805 | 0.0071 | 0.9929 | 69.93 |
| 48.5 | 14,072,197 | 132,823 | 0.0094 | 0.9906 | 69.43 |
| 49.5 | 13,938,402 | 51,045 | 0.0037 | 0.9963 | 68.78 |
| 50.5 | 10,321,555 | 74,481 | 0.0072 | 0.9928 | 68.53 |
| 51.5 | 10,242,146 | 64,008 | 0.0062 | 0.9938 | 68.03 |
| 52.5 | 8,707,127 | 6,773 | 0.0008 | 0.9992 | 67.61 |
| 53.5 | 7,520,898 | 90,346 | 0.0120 | 0.9880 | 67.56 |
| 54.5 | 4,263,981 | 63,207 | 0.0148 | 0.9852 | 66.74 |
| 55.5 | 4,199,412 | | 0.0000 | 1.0000 | 65.75 |
| 56.5 | 3,496,396 | 20,035 | 0.0057 | 0.9943 | 65.75 |
| 57.5 | 3,473,558 | 61,792 | 0.0178 | 0.9822 | 65.38 |
| 58.5 | 2,830,818 | 655 | 0.0002 | 0.9998 | 64.21 |
| 59.5 | 1,803,848 | | 0.0000 | 1.0000 | 64.20 |
| 60.5 | 1,580,892 | | 0.0000 | 1.0000 | 64.20 |
| 61.5 | 835,430 | 50,253 | 0.0602 | 0.9398 | 64.20 |
| 62.5 | 483,392 | 42,225 | 0.0874 | 0.9126 | 60.34 |
| 63.5 | 441,167 | | 0.0000 | 1.0000 | 55.07 |
| 64.5 | 441,167 | | 0.0000 | 1.0000 | 55.07 |
| 65.5 | 441,167 | | 0.0000 | 1.0000 | 55.07 |
| 66.5 | 441,167 | | 0.0000 | 1.0000 | 55.07 |
| 67.5 | 441,167 | | 0.0000 | 1.0000 | 55.07 |
| 68.5 | 441,167 | 35,068 | 0.0795 | 0.9205 | 55.07 |
| 69.5 | 286,630 | 13,675 | 0.0477 | 0.9523 | 50.69 |
| 70.5 | 152,583 | | 0.0000 | 1.0000 | 48.27 |
| 71.5 | 152,583 | | 0.0000 | 1.0000 | 48.27 |
| 72.5 | 152,583 | | 0.0000 | 1.0000 | 48.27 |
| 73.5 | 152,583 | | 0.0000 | 1.0000 | 48.27 |
| 74.5 | 151,629 | | 0.0000 | 1.0000 | 48.27 |
| 75.5 | 151,629 | | 0.0000 | 1.0000 | 48.27 |
| 76.5 | 151,629 | | 0.0000 | 1.0000 | 48.27 |
| 77.5 | 151,629 | | 0.0000 | 1.0000 | 48.27 |
| 78.5 | 151,629 | 33 | 0.0002 | 0.9998 | 48.27 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 151,597 | 1,374 | 0.0091 | 0.9909 | 48.26 |
| 80.5 | 150,223 | | 0.0000 | 1.0000 | 47.82 |
| 81.5 | 150,223 | | 0.0000 | 1.0000 | 47.82 |
| 82.5 | 150,223 | | 0.0000 | 1.0000 | 47.82 |
| 83.5 | 148,676 | 8,291 | 0.0558 | 0.9442 | 47.82 |
| 84.5 | 140,385 | 3,307 | 0.0236 | 0.9764 | 45.16 |
| 85.5 | 137,078 | | 0.0000 | 1.0000 | 44.09 |
| 86.5 | 137,078 | 44,391 | 0.3238 | 0.6762 | 44.09 |
| 87.5 | 92,687 | 63,917 | 0.6896 | 0.3104 | 29.81 |
| 88.5 | 16,640 | | 0.0000 | 1.0000 | 9.25 |
| 89.5 | | | | | 9.25 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 275,127,905 | 2,735 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 265,505,835 | 1,085 | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 266,719,342 | 16 | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 259,693,539 | 77,192 | 0.0003 | 0.9997 | 100.00 |
| 3.5 | 241,038,996 | 17,147 | 0.0001 | 0.9999 | 99.97 |
| 4.5 | 233,893,219 | 5,614 | 0.0000 | 1.0000 | 99.96 |
| 5.5 | 248,179,293 | 227,416 | 0.0009 | 0.9991 | 99.96 |
| 6.5 | 250,817,673 | 3,343,359 | 0.0133 | 0.9867 | 99.87 |
| 7.5 | 239,081,481 | 380,698 | 0.0016 | 0.9984 | 98.54 |
| 8.5 | 236,694,912 | 2,416,191 | 0.0102 | 0.9898 | 98.38 |
| 9.5 | 203,944,892 | 7,087,197 | 0.0348 | 0.9652 | 97.38 |
| 10.5 | 173,465,098 | 1,068,857 | 0.0062 | 0.9938 | 93.99 |
| 11.5 | 131,158,053 | 146,081 | 0.0011 | 0.9989 | 93.41 |
| 12.5 | 126,088,350 | 97,199 | 0.0008 | 0.9992 | 93.31 |
| 13.5 | 111,916,445 | 623,385 | 0.0056 | 0.9944 | 93.24 |
| 14.5 | 109,764,313 | 25,377 | 0.0002 | 0.9998 | 92.72 |
| 15.5 | 100,981,528 | 134,205 | 0.0013 | 0.9987 | 92.70 |
| 16.5 | 103,393,601 | 15,956 | 0.0002 | 0.9998 | 92.57 |
| 17.5 | 100,969,323 | 862,864 | 0.0085 | 0.9915 | 92.56 |
| 18.5 | 100,928,206 | 920,587 | 0.0091 | 0.9909 | 91.77 |
| 19.5 | 99,973,793 | 5,068,326 | 0.0507 | 0.9493 | 90.93 |
| 20.5 | 96,298,725 | 2,106,389 | 0.0219 | 0.9781 | 86.32 |
| 21.5 | 93,177,881 | 1,069,667 | 0.0115 | 0.9885 | 84.43 |
| 22.5 | 92,189,735 | 2,314,772 | 0.0251 | 0.9749 | 83.46 |
| 23.5 | 87,667,492 | 808,446 | 0.0092 | 0.9908 | 81.37 |
| 24.5 | 87,626,101 | 1,029,463 | 0.0117 | 0.9883 | 80.62 |
| 25.5 | 86,312,234 | 38,545 | 0.0004 | 0.9996 | 79.67 |
| 26.5 | 85,560,032 | 1,136,766 | 0.0133 | 0.9867 | 79.63 |
| 27.5 | 80,942,312 | 21,312 | 0.0003 | 0.9997 | 78.58 |
| 28.5 | 77,565,366 | 38,358 | 0.0005 | 0.9995 | 78.56 |
| 29.5 | 73,090,957 | 50,461 | 0.0007 | 0.9993 | 78.52 |
| 30.5 | 72,175,280 | 140,598 | 0.0019 | 0.9981 | 78.46 |
| 31.5 | 75,059,105 | 787,710 | 0.0105 | 0.9895 | 78.31 |
| 32.5 | 74,277,101 | 152,371 | 0.0021 | 0.9979 | 77.49 |
| 33.5 | 73,839,709 | 631,876 | 0.0086 | 0.9914 | 77.33 |
| 34.5 | 72,152,246 | 79,638 | 0.0011 | 0.9989 | 76.67 |
| 35.5 | 47,272,968 | 126,568 | 0.0027 | 0.9973 | 76.58 |
| 36.5 | 45,378,217 | 203,816 | 0.0045 | 0.9955 | 76.38 |
| 37.5 | 44,421,697 | 1,703,460 | 0.0383 | 0.9617 | 76.03 |
| 38.5 | 31,899,476 | 34,046 | 0.0011 | 0.9989 | 73.12 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 30,533,849 | 84,140 | 0.0028 | 0.9972 | 73.04 |
| 40.5 | 30,004,813 | 21,706 | 0.0007 | 0.9993 | 72.84 |
| 41.5 | 24,708,532 | 296,200 | 0.0120 | 0.9880 | 72.79 |
| 42.5 | 23,525,072 | 221,096 | 0.0094 | 0.9906 | 71.91 |
| 43.5 | 23,259,913 | 175,718 | 0.0076 | 0.9924 | 71.24 |
| 44.5 | 23,048,623 | 446,014 | 0.0194 | 0.9806 | 70.70 |
| 45.5 | 16,657,536 | 62,590 | 0.0038 | 0.9962 | 69.33 |
| 46.5 | 16,534,914 | 30,244 | 0.0018 | 0.9982 | 69.07 |
| 47.5 | 14,053,198 | 100,805 | 0.0072 | 0.9928 | 68.95 |
| 48.5 | 13,869,802 | 132,823 | 0.0096 | 0.9904 | 68.45 |
| 49.5 | 13,737,554 | 49,022 | 0.0036 | 0.9964 | 67.80 |
| 50.5 | 10,122,729 | 74,481 | 0.0074 | 0.9926 | 67.55 |
| 51.5 | 10,051,612 | 64,008 | 0.0064 | 0.9936 | 67.06 |
| 52.5 | 8,519,900 | 6,773 | 0.0008 | 0.9992 | 66.63 |
| 53.5 | 7,333,671 | 90,346 | 0.0123 | 0.9877 | 66.58 |
| 54.5 | 4,168,375 | 63,207 | 0.0152 | 0.9848 | 65.76 |
| 55.5 | 4,199,412 | | 0.0000 | 1.0000 | 64.76 |
| 56.5 | 3,496,396 | 20,035 | 0.0057 | 0.9943 | 64.76 |
| 57.5 | 3,473,558 | 61,792 | 0.0178 | 0.9822 | 64.39 |
| 58.5 | 2,830,818 | 655 | 0.0002 | 0.9998 | 63.24 |
| 59.5 | 1,803,848 | | 0.0000 | 1.0000 | 63.23 |
| 60.5 | 1,580,892 | | 0.0000 | 1.0000 | 63.23 |
| 61.5 | 835,430 | 50,253 | 0.0602 | 0.9398 | 63.23 |
| 62.5 | 483,392 | 42,225 | 0.0874 | 0.9126 | 59.42 |
| 63.5 | 441,167 | | 0.0000 | 1.0000 | 54.23 |
| 64.5 | 441,167 | | 0.0000 | 1.0000 | 54.23 |
| 65.5 | 441,167 | | 0.0000 | 1.0000 | 54.23 |
| 66.5 | 441,167 | | 0.0000 | 1.0000 | 54.23 |
| 67.5 | 441,167 | | 0.0000 | 1.0000 | 54.23 |
| 68.5 | 441,167 | 35,068 | 0.0795 | 0.9205 | 54.23 |
| 69.5 | 286,630 | 13,675 | 0.0477 | 0.9523 | 49.92 |
| 70.5 | 152,583 | | 0.0000 | 1.0000 | 47.54 |
| 71.5 | 152,583 | | 0.0000 | 1.0000 | 47.54 |
| 72.5 | 152,583 | | 0.0000 | 1.0000 | 47.54 |
| 73.5 | 152,583 | | 0.0000 | 1.0000 | 47.54 |
| 74.5 | 151,629 | | 0.0000 | 1.0000 | 47.54 |
| 75.5 | 151,629 | | 0.0000 | 1.0000 | 47.54 |
| 76.5 | 151,629 | | 0.0000 | 1.0000 | 47.54 |
| 77.5 | 151,629 | | 0.0000 | 1.0000 | 47.54 |
| 78.5 | 151,629 | 33 | 0.0002 | 0.9998 | 47.54 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 151,597 | 1,374 | 0.0091 | 0.9909 | 47.53 |
| 80.5 | 150,223 | | 0.0000 | 1.0000 | 47.10 |
| 81.5 | 150,223 | | 0.0000 | 1.0000 | 47.10 |
| 82.5 | 150,223 | | 0.0000 | 1.0000 | 47.10 |
| 83.5 | 148,676 | 8,291 | 0.0558 | 0.9442 | 47.10 |
| 84.5 | 140,385 | 3,307 | 0.0236 | 0.9764 | 44.47 |
| 85.5 | 137,078 | | 0.0000 | 1.0000 | 43.43 |
| 86.5 | 137,078 | 44,391 | 0.3238 | 0.6762 | 43.43 |
| 87.5 | 92,687 | 63,917 | 0.6896 | 0.3104 | 29.36 |
| 88.5 | 16,640 | | 0.0000 | 1.0000 | 9.11 |
| 89.5 | | | | | 9.11 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 199,352,935 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 190,965,467 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 192,152,861 | 14 | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 186,891,500 | 76,758 | 0.0004 | 0.9996 | 100.00 |
| 3.5 | 170,516,604 | 14,610 | 0.0001 | 0.9999 | 99.96 |
| 4.5 | 162,837,870 | 204 | 0.0000 | 1.0000 | 99.95 |
| 5.5 | 164,228,976 | 226,576 | 0.0014 | 0.9986 | 99.95 |
| 6.5 | 164,996,392 | 3,308,711 | 0.0201 | 0.9799 | 99.81 |
| 7.5 | 157,095,555 | 376,493 | 0.0024 | 0.9976 | 97.81 |
| 8.5 | 158,081,022 | 23,085 | 0.0001 | 0.9999 | 97.58 |
| 9.5 | 130,445,048 | 4,505,510 | 0.0345 | 0.9655 | 97.56 |
| 10.5 | 101,864,608 | 676,722 | 0.0066 | 0.9934 | 94.19 |
| 11.5 | 61,207,106 | 98,157 | 0.0016 | 0.9984 | 93.57 |
| 12.5 | 53,647,729 | 33,755 | 0.0006 | 0.9994 | 93.42 |
| 13.5 | 39,286,081 | 122,962 | 0.0031 | 0.9969 | 93.36 |
| 14.5 | 40,158,342 | 4,728 | 0.0001 | 0.9999 | 93.07 |
| 15.5 | 55,195,824 | 107,677 | 0.0020 | 0.9980 | 93.05 |
| 16.5 | 55,918,054 | 7,956 | 0.0001 | 0.9999 | 92.87 |
| 17.5 | 54,242,696 | 168,675 | 0.0031 | 0.9969 | 92.86 |
| 18.5 | 64,582,941 | 272,720 | 0.0042 | 0.9958 | 92.57 |
| 19.5 | 65,325,494 | 928,104 | 0.0142 | 0.9858 | 92.18 |
| 20.5 | 63,789,623 | 2,092,193 | 0.0328 | 0.9672 | 90.87 |
| 21.5 | 62,785,438 | 994,931 | 0.0158 | 0.9842 | 87.89 |
| 22.5 | 61,596,900 | 39,007 | 0.0006 | 0.9994 | 86.50 |
| 23.5 | 60,041,937 | 808,446 | 0.0135 | 0.9865 | 86.44 |
| 24.5 | 59,265,886 | 495,770 | 0.0084 | 0.9916 | 85.28 |
| 25.5 | 65,516,900 | 38,545 | 0.0006 | 0.9994 | 84.57 |
| 26.5 | 68,943,299 | 587,510 | 0.0085 | 0.9915 | 84.52 |
| 27.5 | 66,724,948 | 12,135 | 0.0002 | 0.9998 | 83.80 |
| 28.5 | 63,121,277 | 36,202 | 0.0006 | 0.9994 | 83.78 |
| 29.5 | 58,186,247 | 48,686 | 0.0008 | 0.9992 | 83.73 |
| 30.5 | 59,268,675 | 140,598 | 0.0024 | 0.9976 | 83.66 |
| 31.5 | 62,168,400 | 787,710 | 0.0127 | 0.9873 | 83.46 |
| 32.5 | 62,985,740 | 49,066 | 0.0008 | 0.9992 | 82.41 |
| 33.5 | 62,652,033 | 619,780 | 0.0099 | 0.9901 | 82.34 |
| 34.5 | 62,162,176 | 61,100 | 0.0010 | 0.9990 | 81.53 |
| 35.5 | 37,141,514 | 126,568 | 0.0034 | 0.9966 | 81.45 |
| 36.5 | 36,950,298 | 185,876 | 0.0050 | 0.9950 | 81.17 |
| 37.5 | 36,011,790 | 1,703,460 | 0.0473 | 0.9527 | 80.76 |
| 38.5 | 24,923,136 | 34,046 | 0.0014 | 0.9986 | 76.94 |

DUKE ENERGY PROGRESS

ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 23,672,664 | 69,446 | 0.0029 | 0.9971 | 76.84 |
| 40.5 | 25,453,957 | 4,070 | 0.0002 | 0.9998 | 76.61 |
| 41.5 | 20,181,835 | 248,797 | 0.0123 | 0.9877 | 76.60 |
| 42.5 | 19,885,412 | 148,834 | 0.0075 | 0.9925 | 75.65 |
| 43.5 | 20,273,890 | 116,395 | 0.0057 | 0.9943 | 75.09 |
| 44.5 | 20,959,115 | 352,982 | 0.0168 | 0.9832 | 74.66 |
| 45.5 | 14,661,060 | 27,439 | 0.0019 | 0.9981 | 73.40 |
| 46.5 | 15,087,286 | 30,244 | 0.0020 | 0.9980 | 73.26 |
| 47.5 | 13,220,038 | 100,805 | 0.0076 | 0.9924 | 73.12 |
| 48.5 | 13,177,784 | 132,823 | 0.0101 | 0.9899 | 72.56 |
| 49.5 | 13,402,079 | 49,022 | 0.0037 | 0.9963 | 71.83 |
| 50.5 | 9,787,255 | 74,481 | 0.0076 | 0.9924 | 71.56 |
| 51.5 | 9,707,846 | 64,008 | 0.0066 | 0.9934 | 71.02 |
| 52.5 | 8,173,482 | 6,773 | 0.0008 | 0.9992 | 70.55 |
| 53.5 | 6,987,253 | 90,346 | 0.0129 | 0.9871 | 70.49 |
| 54.5 | 3,730,336 | 63,207 | 0.0169 | 0.9831 | 69.58 |
| 55.5 | 3,835,488 | | 0.0000 | 1.0000 | 68.40 |
| 56.5 | 3,295,070 | 20,035 | 0.0061 | 0.9939 | 68.40 |
| 57.5 | 3,272,232 | 61,792 | 0.0189 | 0.9811 | 67.99 |
| 58.5 | 2,629,491 | 655 | 0.0002 | 0.9998 | 66.70 |
| 59.5 | 1,602,522 | | 0.0000 | 1.0000 | 66.69 |
| 60.5 | 1,380,520 | | 0.0000 | 1.0000 | 66.69 |
| 61.5 | 635,058 | 50,253 | 0.0791 | 0.9209 | 66.69 |
| 62.5 | 283,020 | 42,225 | 0.1492 | 0.8508 | 61.41 |
| 63.5 | 240,795 | | 0.0000 | 1.0000 | 52.25 |
| 64.5 | 240,795 | | 0.0000 | 1.0000 | 52.25 |
| 65.5 | 240,795 | | 0.0000 | 1.0000 | 52.25 |
| 66.5 | 240,795 | | 0.0000 | 1.0000 | 52.25 |
| 67.5 | 240,795 | | 0.0000 | 1.0000 | 52.25 |
| 68.5 | 240,795 | | 0.0000 | 1.0000 | 52.25 |
| 69.5 | 122,873 | | 0.0000 | 1.0000 | 52.25 |
| 70.5 | 2,501 | | 0.0000 | 1.0000 | 52.25 |
| 71.5 | 10,792 | | 0.0000 | 1.0000 | 52.25 |
| 72.5 | 14,099 | | 0.0000 | 1.0000 | 52.25 |
| 73.5 | 14,099 | | 0.0000 | 1.0000 | 52.25 |
| 74.5 | 69,698 | | 0.0000 | 1.0000 | 52.25 |
| 75.5 | 151,629 | | 0.0000 | 1.0000 | 52.25 |
| 76.5 | 151,629 | | 0.0000 | 1.0000 | 52.25 |
| 77.5 | 151,629 | | 0.0000 | 1.0000 | 52.25 |
| 78.5 | 151,629 | 33 | 0.0002 | 0.9998 | 52.25 |

DUKE ENERGY PROGRESS

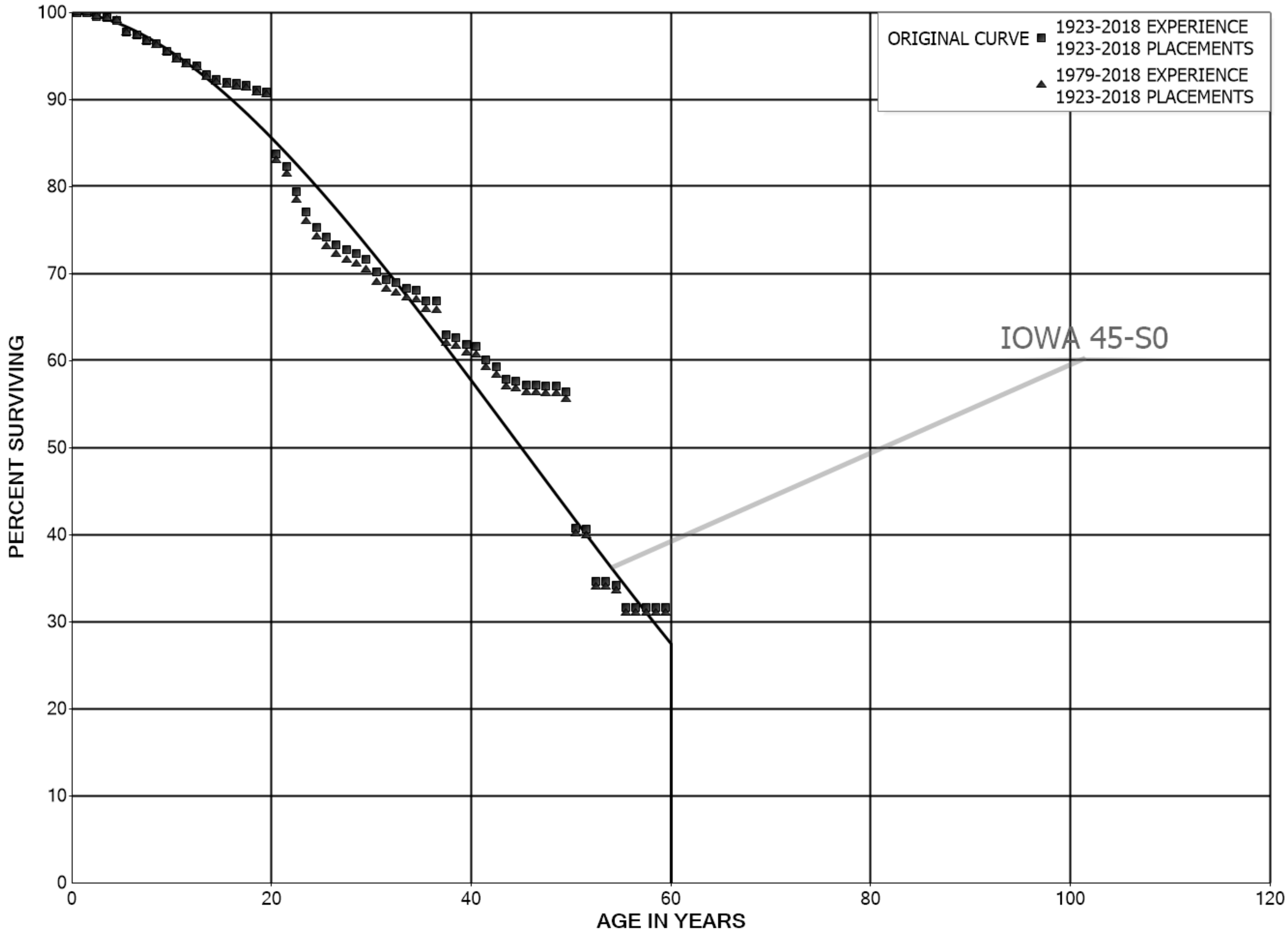
ACCOUNT 315 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 151,597 | 1,374 | 0.0091 | 0.9909 | 52.24 |
| 80.5 | 150,223 | | 0.0000 | 1.0000 | 51.76 |
| 81.5 | 150,223 | | 0.0000 | 1.0000 | 51.76 |
| 82.5 | 150,223 | | 0.0000 | 1.0000 | 51.76 |
| 83.5 | 148,676 | 8,291 | 0.0558 | 0.9442 | 51.76 |
| 84.5 | 140,385 | 3,307 | 0.0236 | 0.9764 | 48.88 |
| 85.5 | 137,078 | | 0.0000 | 1.0000 | 47.72 |
| 86.5 | 137,078 | 44,391 | 0.3238 | 0.6762 | 47.72 |
| 87.5 | 92,687 | 63,917 | 0.6896 | 0.3104 | 32.27 |
| 88.5 | 16,640 | | 0.0000 | 1.0000 | 10.02 |
| 89.5 | | | | | 10.02 |

DUKE ENERGY PROGRESS
ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 94,813,834 | 50,308 | 0.0005 | 0.9995 | 100.00 |
| 0.5 | 92,452,179 | 33,711 | 0.0004 | 0.9996 | 99.95 |
| 1.5 | 89,938,231 | 369,041 | 0.0041 | 0.9959 | 99.91 |
| 2.5 | 83,093,632 | 129,379 | 0.0016 | 0.9984 | 99.50 |
| 3.5 | 77,669,892 | 214,576 | 0.0028 | 0.9972 | 99.35 |
| 4.5 | 72,970,361 | 1,030,014 | 0.0141 | 0.9859 | 99.07 |
| 5.5 | 69,150,740 | 194,134 | 0.0028 | 0.9972 | 97.67 |
| 6.5 | 64,771,604 | 433,189 | 0.0067 | 0.9933 | 97.40 |
| 7.5 | 62,150,493 | 235,888 | 0.0038 | 0.9962 | 96.75 |
| 8.5 | 59,872,080 | 516,222 | 0.0086 | 0.9914 | 96.38 |
| 9.5 | 56,068,291 | 436,432 | 0.0078 | 0.9922 | 95.55 |
| 10.5 | 51,117,158 | 319,627 | 0.0063 | 0.9937 | 94.81 |
| 11.5 | 41,893,283 | 149,337 | 0.0036 | 0.9964 | 94.21 |
| 12.5 | 37,301,327 | 406,323 | 0.0109 | 0.9891 | 93.88 |
| 13.5 | 29,845,898 | 190,453 | 0.0064 | 0.9936 | 92.85 |
| 14.5 | 28,799,203 | 102,040 | 0.0035 | 0.9965 | 92.26 |
| 15.5 | 27,331,821 | 45,292 | 0.0017 | 0.9983 | 91.93 |
| 16.5 | 26,876,919 | 60,358 | 0.0022 | 0.9978 | 91.78 |
| 17.5 | 26,372,586 | 150,767 | 0.0057 | 0.9943 | 91.58 |
| 18.5 | 25,400,312 | 46,691 | 0.0018 | 0.9982 | 91.05 |
| 19.5 | 24,832,920 | 1,966,222 | 0.0792 | 0.9208 | 90.89 |
| 20.5 | 21,366,484 | 369,623 | 0.0173 | 0.9827 | 83.69 |
| 21.5 | 20,344,133 | 704,783 | 0.0346 | 0.9654 | 82.24 |
| 22.5 | 18,605,137 | 556,438 | 0.0299 | 0.9701 | 79.39 |
| 23.5 | 17,513,661 | 392,622 | 0.0224 | 0.9776 | 77.02 |
| 24.5 | 16,813,210 | 247,461 | 0.0147 | 0.9853 | 75.29 |
| 25.5 | 16,395,209 | 189,911 | 0.0116 | 0.9884 | 74.18 |
| 26.5 | 15,577,215 | 128,830 | 0.0083 | 0.9917 | 73.32 |
| 27.5 | 15,026,570 | 85,070 | 0.0057 | 0.9943 | 72.72 |
| 28.5 | 14,432,852 | 146,221 | 0.0101 | 0.9899 | 72.31 |
| 29.5 | 13,531,549 | 274,310 | 0.0203 | 0.9797 | 71.57 |
| 30.5 | 13,167,147 | 159,152 | 0.0121 | 0.9879 | 70.12 |
| 31.5 | 13,395,623 | 72,323 | 0.0054 | 0.9946 | 69.27 |
| 32.5 | 13,034,370 | 106,508 | 0.0082 | 0.9918 | 68.90 |
| 33.5 | 12,497,589 | 41,085 | 0.0033 | 0.9967 | 68.34 |
| 34.5 | 12,291,830 | 222,006 | 0.0181 | 0.9819 | 68.11 |
| 35.5 | 7,499,132 | 10,376 | 0.0014 | 0.9986 | 66.88 |
| 36.5 | 7,321,108 | 419,823 | 0.0573 | 0.9427 | 66.79 |
| 37.5 | 6,583,548 | 38,990 | 0.0059 | 0.9941 | 62.96 |
| 38.5 | 4,569,204 | 58,630 | 0.0128 | 0.9872 | 62.59 |

DUKE ENERGY PROGRESS

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 4,186,251 | 10,767 | 0.0026 | 0.9974 | 61.78 |
| 40.5 | 4,113,980 | 101,094 | 0.0246 | 0.9754 | 61.63 |
| 41.5 | 3,844,175 | 54,393 | 0.0141 | 0.9859 | 60.11 |
| 42.5 | 3,732,607 | 89,201 | 0.0239 | 0.9761 | 59.26 |
| 43.5 | 3,563,909 | 15,085 | 0.0042 | 0.9958 | 57.84 |
| 44.5 | 3,546,597 | 26,972 | 0.0076 | 0.9924 | 57.60 |
| 45.5 | 2,668,214 | 1,386 | 0.0005 | 0.9995 | 57.16 |
| 46.5 | 2,658,534 | 2,183 | 0.0008 | 0.9992 | 57.13 |
| 47.5 | 2,518,278 | 806 | 0.0003 | 0.9997 | 57.08 |
| 48.5 | 2,509,369 | 30,880 | 0.0123 | 0.9877 | 57.07 |
| 49.5 | 2,476,663 | 685,022 | 0.2766 | 0.7234 | 56.36 |
| 50.5 | 1,600,856 | 7,407 | 0.0046 | 0.9954 | 40.77 |
| 51.5 | 1,588,352 | 233,337 | 0.1469 | 0.8531 | 40.59 |
| 52.5 | 1,323,001 | | 0.0000 | 1.0000 | 34.62 |
| 53.5 | 1,058,128 | 14,972 | 0.0141 | 0.9859 | 34.62 |
| 54.5 | 1,039,617 | 75,712 | 0.0728 | 0.9272 | 34.13 |
| 55.5 | 949,666 | | 0.0000 | 1.0000 | 31.65 |
| 56.5 | 814,617 | 102 | 0.0001 | 0.9999 | 31.65 |
| 57.5 | 813,593 | 33 | 0.0000 | 1.0000 | 31.64 |
| 58.5 | 764,908 | | 0.0000 | 1.0000 | 31.64 |
| 59.5 | 443,290 | 282 | 0.0006 | 0.9994 | 31.64 |
| 60.5 | 326,667 | 708 | 0.0022 | 0.9978 | 31.62 |
| 61.5 | 157,872 | | 0.0000 | 1.0000 | 31.55 |
| 62.5 | 15,436 | | 0.0000 | 1.0000 | 31.55 |
| 63.5 | 15,436 | 37 | 0.0024 | 0.9976 | 31.55 |
| 64.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 65.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 66.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 67.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 68.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 69.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 70.5 | 15,399 | | 0.0000 | 1.0000 | 31.48 |
| 71.5 | 15,399 | 100 | 0.0065 | 0.9935 | 31.48 |
| 72.5 | 15,299 | | 0.0000 | 1.0000 | 31.27 |
| 73.5 | 15,299 | | 0.0000 | 1.0000 | 31.27 |
| 74.5 | 15,299 | | 0.0000 | 1.0000 | 31.27 |
| 75.5 | 15,299 | 127 | 0.0083 | 0.9917 | 31.27 |
| 76.5 | 15,172 | 2,400 | 0.1582 | 0.8418 | 31.01 |
| 77.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 78.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |

DUKE ENERGY PROGRESS

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1923-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 80.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 81.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 82.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 83.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 84.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 85.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 86.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 87.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 88.5 | 12,772 | | 0.0000 | 1.0000 | 26.11 |
| 89.5 | | | | | 26.11 |
| 90.5 | 4,590 | | 0.0000 | | |
| 91.5 | 4,590 | | 0.0000 | | |
| 92.5 | 4,590 | 4,590 | 1.0000 | | |
| 93.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 85,636,246 | 12,088 | 0.0001 | 0.9999 | 100.00 |
| 0.5 | 85,051,353 | 32,034 | 0.0004 | 0.9996 | 99.99 |
| 1.5 | 82,787,248 | 368,008 | 0.0044 | 0.9956 | 99.95 |
| 2.5 | 76,078,453 | 126,464 | 0.0017 | 0.9983 | 99.50 |
| 3.5 | 70,863,433 | 198,785 | 0.0028 | 0.9972 | 99.34 |
| 4.5 | 66,516,620 | 993,140 | 0.0149 | 0.9851 | 99.06 |
| 5.5 | 64,069,674 | 193,084 | 0.0030 | 0.9970 | 97.58 |
| 6.5 | 59,854,320 | 428,206 | 0.0072 | 0.9928 | 97.29 |
| 7.5 | 58,491,887 | 233,737 | 0.0040 | 0.9960 | 96.59 |
| 8.5 | 56,245,120 | 501,162 | 0.0089 | 0.9911 | 96.20 |
| 9.5 | 52,459,884 | 434,210 | 0.0083 | 0.9917 | 95.35 |
| 10.5 | 47,994,643 | 303,551 | 0.0063 | 0.9937 | 94.56 |
| 11.5 | 38,802,807 | 146,442 | 0.0038 | 0.9962 | 93.96 |
| 12.5 | 34,638,248 | 404,411 | 0.0117 | 0.9883 | 93.61 |
| 13.5 | 27,211,160 | 182,633 | 0.0067 | 0.9933 | 92.51 |
| 14.5 | 26,540,837 | 95,200 | 0.0036 | 0.9964 | 91.89 |
| 15.5 | 25,086,231 | 38,126 | 0.0015 | 0.9985 | 91.56 |
| 16.5 | 24,853,868 | 49,822 | 0.0020 | 0.9980 | 91.42 |
| 17.5 | 24,368,994 | 148,848 | 0.0061 | 0.9939 | 91.24 |
| 18.5 | 23,815,284 | 45,949 | 0.0019 | 0.9981 | 90.68 |
| 19.5 | 23,401,281 | 1,962,392 | 0.0839 | 0.9161 | 90.51 |
| 20.5 | 20,061,098 | 367,052 | 0.0183 | 0.9817 | 82.92 |
| 21.5 | 19,043,246 | 691,187 | 0.0363 | 0.9637 | 81.40 |
| 22.5 | 17,453,533 | 550,796 | 0.0316 | 0.9684 | 78.45 |
| 23.5 | 16,412,842 | 391,989 | 0.0239 | 0.9761 | 75.97 |
| 24.5 | 16,022,559 | 246,317 | 0.0154 | 0.9846 | 74.16 |
| 25.5 | 15,610,005 | 189,811 | 0.0122 | 0.9878 | 73.02 |
| 26.5 | 15,045,459 | 128,298 | 0.0085 | 0.9915 | 72.13 |
| 27.5 | 14,755,522 | 85,070 | 0.0058 | 0.9942 | 71.51 |
| 28.5 | 14,203,275 | 138,332 | 0.0097 | 0.9903 | 71.10 |
| 29.5 | 13,501,776 | 273,897 | 0.0203 | 0.9797 | 70.41 |
| 30.5 | 13,137,787 | 159,152 | 0.0121 | 0.9879 | 68.98 |
| 31.5 | 13,367,761 | 72,323 | 0.0054 | 0.9946 | 68.14 |
| 32.5 | 13,006,508 | 105,337 | 0.0081 | 0.9919 | 67.78 |
| 33.5 | 12,470,899 | 41,058 | 0.0033 | 0.9967 | 67.23 |
| 34.5 | 12,265,200 | 213,806 | 0.0174 | 0.9826 | 67.01 |
| 35.5 | 7,480,702 | 10,376 | 0.0014 | 0.9986 | 65.84 |
| 36.5 | 7,303,071 | 419,823 | 0.0575 | 0.9425 | 65.75 |
| 37.5 | 6,565,511 | 38,990 | 0.0059 | 0.9941 | 61.97 |
| 38.5 | 4,551,167 | 58,630 | 0.0129 | 0.9871 | 61.60 |

DUKE ENERGY PROGRESS

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 4,168,214 | 10,627 | 0.0025 | 0.9975 | 60.81 |
| 40.5 | 4,096,083 | 101,094 | 0.0247 | 0.9753 | 60.65 |
| 41.5 | 3,826,278 | 53,393 | 0.0140 | 0.9860 | 59.15 |
| 42.5 | 3,715,710 | 89,201 | 0.0240 | 0.9760 | 58.33 |
| 43.5 | 3,547,114 | 15,085 | 0.0043 | 0.9957 | 56.93 |
| 44.5 | 3,529,801 | 26,072 | 0.0074 | 0.9926 | 56.69 |
| 45.5 | 2,652,318 | 1,386 | 0.0005 | 0.9995 | 56.27 |
| 46.5 | 2,642,639 | 2,183 | 0.0008 | 0.9992 | 56.24 |
| 47.5 | 2,502,382 | 806 | 0.0003 | 0.9997 | 56.19 |
| 48.5 | 2,493,511 | 30,880 | 0.0124 | 0.9876 | 56.17 |
| 49.5 | 2,460,805 | 685,022 | 0.2784 | 0.7216 | 55.48 |
| 50.5 | 1,584,997 | 7,347 | 0.0046 | 0.9954 | 40.03 |
| 51.5 | 1,572,553 | 233,337 | 0.1484 | 0.8516 | 39.85 |
| 52.5 | 1,309,729 | | 0.0000 | 1.0000 | 33.94 |
| 53.5 | 1,044,857 | 14,573 | 0.0139 | 0.9861 | 33.94 |
| 54.5 | 1,026,745 | 75,712 | 0.0737 | 0.9263 | 33.46 |
| 55.5 | 949,666 | | 0.0000 | 1.0000 | 30.99 |
| 56.5 | 814,617 | 102 | 0.0001 | 0.9999 | 30.99 |
| 57.5 | 813,593 | 33 | 0.0000 | 1.0000 | 30.99 |
| 58.5 | 764,908 | | 0.0000 | 1.0000 | 30.99 |
| 59.5 | 443,290 | 282 | 0.0006 | 0.9994 | 30.99 |
| 60.5 | 326,667 | 708 | 0.0022 | 0.9978 | 30.97 |
| 61.5 | 157,872 | | 0.0000 | 1.0000 | 30.90 |
| 62.5 | 15,436 | | 0.0000 | 1.0000 | 30.90 |
| 63.5 | 15,436 | 37 | 0.0024 | 0.9976 | 30.90 |
| 64.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 65.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 66.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 67.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 68.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 69.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 70.5 | 15,399 | | 0.0000 | 1.0000 | 30.83 |
| 71.5 | 15,399 | 100 | 0.0065 | 0.9935 | 30.83 |
| 72.5 | 15,299 | | 0.0000 | 1.0000 | 30.63 |
| 73.5 | 15,299 | | 0.0000 | 1.0000 | 30.63 |
| 74.5 | 15,299 | | 0.0000 | 1.0000 | 30.63 |
| 75.5 | 15,299 | 127 | 0.0083 | 0.9917 | 30.63 |
| 76.5 | 15,172 | 2,400 | 0.1582 | 0.8418 | 30.37 |
| 77.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 78.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |

DUKE ENERGY PROGRESS

ACCOUNT 316 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 80.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 81.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 82.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 83.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 84.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 85.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 86.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 87.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 88.5 | 12,772 | | 0.0000 | 1.0000 | 25.57 |
| 89.5 | | | | | 25.57 |
| 90.5 | 4,590 | | 0.0000 | | |
| 91.5 | 4,590 | | 0.0000 | | |
| 92.5 | 4,590 | 4,590 | 1.0000 | | |
| 93.5 | | | | | |

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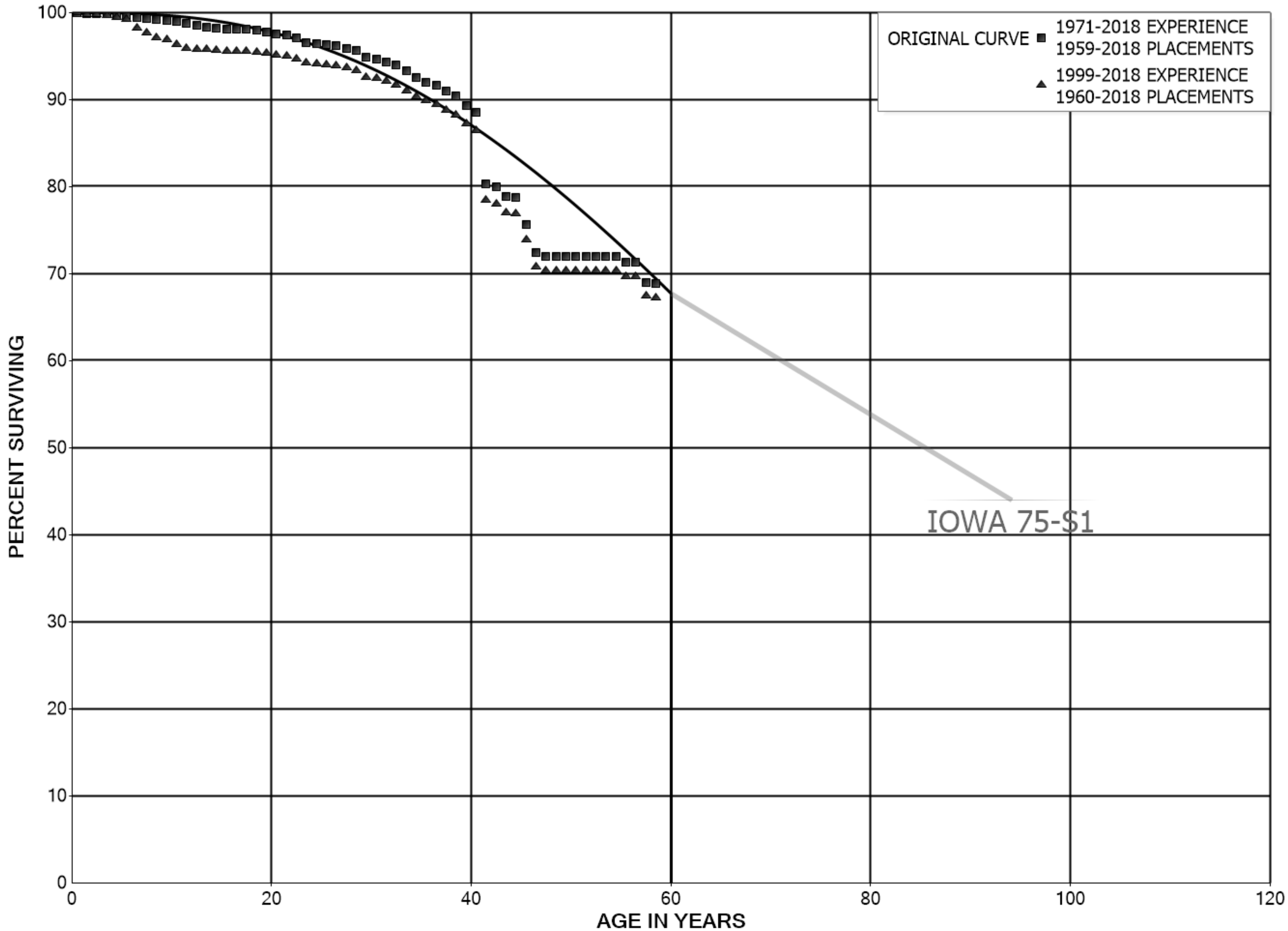
DUKE ENERGY PROGRESS
ACCOUNT 321 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 2,937,444,557 | 1,294,439 | 0.0004 | 0.9996 | 100.00 |
| 0.5 | 2,662,977,363 | 2,845,724 | 0.0011 | 0.9989 | 99.96 |
| 1.5 | 2,477,889,873 | 250,292 | 0.0001 | 0.9999 | 99.85 |
| 2.5 | 2,399,188,371 | 1,266,912 | 0.0005 | 0.9995 | 99.84 |
| 3.5 | 2,254,376,146 | 2,294,016 | 0.0010 | 0.9990 | 99.79 |
| 4.5 | 2,226,967,966 | 1,196,874 | 0.0005 | 0.9995 | 99.68 |
| 5.5 | 2,180,732,734 | 4,141,614 | 0.0019 | 0.9981 | 99.63 |
| 6.5 | 2,113,740,653 | 2,560,600 | 0.0012 | 0.9988 | 99.44 |
| 7.5 | 2,040,169,742 | 3,574,416 | 0.0018 | 0.9982 | 99.32 |
| 8.5 | 1,973,246,818 | 1,011,575 | 0.0005 | 0.9995 | 99.15 |
| 9.5 | 1,953,405,826 | 2,453,513 | 0.0013 | 0.9987 | 99.10 |
| 10.5 | 1,931,673,988 | 5,366,550 | 0.0028 | 0.9972 | 98.97 |
| 11.5 | 1,917,023,063 | 4,747,183 | 0.0025 | 0.9975 | 98.70 |
| 12.5 | 1,890,763,254 | 2,343,408 | 0.0012 | 0.9988 | 98.45 |
| 13.5 | 1,873,218,696 | 3,259,937 | 0.0017 | 0.9983 | 98.33 |
| 14.5 | 1,866,853,086 | 1,434,440 | 0.0008 | 0.9992 | 98.16 |
| 15.5 | 1,859,898,970 | 391,745 | 0.0002 | 0.9998 | 98.08 |
| 16.5 | 1,851,362,672 | 924,179 | 0.0005 | 0.9995 | 98.06 |
| 17.5 | 1,849,730,141 | 1,138,001 | 0.0006 | 0.9994 | 98.01 |
| 18.5 | 1,840,223,659 | 4,217,908 | 0.0023 | 0.9977 | 97.95 |
| 19.5 | 1,831,643,121 | 3,879,611 | 0.0021 | 0.9979 | 97.73 |
| 20.5 | 1,827,951,020 | 2,768,539 | 0.0015 | 0.9985 | 97.52 |
| 21.5 | 1,819,293,590 | 5,081,741 | 0.0028 | 0.9972 | 97.38 |
| 22.5 | 1,791,639,979 | 10,181,607 | 0.0057 | 0.9943 | 97.10 |
| 23.5 | 1,753,014,973 | 3,663,151 | 0.0021 | 0.9979 | 96.55 |
| 24.5 | 1,717,035,356 | 1,920,751 | 0.0011 | 0.9989 | 96.35 |
| 25.5 | 1,705,772,196 | 1,944,627 | 0.0011 | 0.9989 | 96.24 |
| 26.5 | 1,669,609,889 | 4,382,367 | 0.0026 | 0.9974 | 96.13 |
| 27.5 | 1,970,259,139 | 5,190,928 | 0.0026 | 0.9974 | 95.88 |
| 28.5 | 1,954,681,217 | 16,792,121 | 0.0086 | 0.9914 | 95.63 |
| 29.5 | 1,892,219,020 | 3,402,688 | 0.0018 | 0.9982 | 94.81 |
| 30.5 | 1,838,336,163 | 6,706,516 | 0.0036 | 0.9964 | 94.64 |
| 31.5 | 336,054,484 | 1,352,269 | 0.0040 | 0.9960 | 94.29 |
| 32.5 | 300,291,900 | 2,135,882 | 0.0071 | 0.9929 | 93.91 |
| 33.5 | 291,059,161 | 2,422,740 | 0.0083 | 0.9917 | 93.24 |
| 34.5 | 265,602,134 | 1,349,824 | 0.0051 | 0.9949 | 92.47 |
| 35.5 | 233,172,301 | 993,910 | 0.0043 | 0.9957 | 92.00 |
| 36.5 | 230,318,958 | 1,774,912 | 0.0077 | 0.9923 | 91.60 |
| 37.5 | 228,464,232 | 1,289,639 | 0.0056 | 0.9944 | 90.90 |
| 38.5 | 212,342,798 | 2,594,822 | 0.0122 | 0.9878 | 90.39 |

DUKE ENERGY PROGRESS

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 210,669,298 | 1,826,109 | 0.0087 | 0.9913 | 89.28 |
| 40.5 | 205,945,569 | 19,051,897 | 0.0925 | 0.9075 | 88.51 |
| 41.5 | 129,497,071 | 666,409 | 0.0051 | 0.9949 | 80.32 |
| 42.5 | 125,492,175 | 1,668,385 | 0.0133 | 0.9867 | 79.91 |
| 43.5 | 18,643,582 | 38,920 | 0.0021 | 0.9979 | 78.84 |
| 44.5 | 18,538,285 | 718,787 | 0.0388 | 0.9612 | 78.68 |
| 45.5 | 17,800,074 | 751,953 | 0.0422 | 0.9578 | 75.63 |
| 46.5 | 16,787,293 | 99,789 | 0.0059 | 0.9941 | 72.43 |
| 47.5 | 2,734 | | 0.0000 | 1.0000 | 72.00 |
| 48.5 | 2,797 | | 0.0000 | 1.0000 | 72.00 |
| 49.5 | 2,612 | | 0.0000 | 1.0000 | 72.00 |
| 50.5 | 3,606 | | 0.0000 | 1.0000 | 72.00 |
| 51.5 | 1,999 | | 0.0000 | 1.0000 | 72.00 |
| 52.5 | 3,584,946 | | 0.0000 | 1.0000 | 72.00 |
| 53.5 | 4,925,264 | | 0.0000 | 1.0000 | 72.00 |
| 54.5 | 4,925,264 | 46,627 | 0.0095 | 0.9905 | 72.00 |
| 55.5 | 4,877,208 | 2,485 | 0.0005 | 0.9995 | 71.32 |
| 56.5 | 4,874,724 | 155,707 | 0.0319 | 0.9681 | 71.28 |
| 57.5 | 4,719,016 | 9,161 | 0.0019 | 0.9981 | 69.01 |
| 58.5 | | | | | 68.87 |

DUKE ENERGY PROGRESS

ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 949,636,283 | 0 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 736,814,309 | 1,910,398 | 0.0026 | 0.9974 | 100.00 |
| 1.5 | 609,925,043 | 200,504 | 0.0003 | 0.9997 | 99.74 |
| 2.5 | 560,069,423 | 317,471 | 0.0006 | 0.9994 | 99.71 |
| 3.5 | 437,128,642 | 1,339,088 | 0.0031 | 0.9969 | 99.65 |
| 4.5 | 441,162,141 | 750,742 | 0.0017 | 0.9983 | 99.35 |
| 5.5 | 422,418,006 | 4,105,387 | 0.0097 | 0.9903 | 99.18 |
| 6.5 | 391,191,719 | 2,208,128 | 0.0056 | 0.9944 | 98.21 |
| 7.5 | 371,546,989 | 2,258,305 | 0.0061 | 0.9939 | 97.66 |
| 8.5 | 317,616,381 | 623,037 | 0.0020 | 0.9980 | 97.07 |
| 9.5 | 343,758,321 | 1,981,850 | 0.0058 | 0.9942 | 96.87 |
| 10.5 | 369,473,239 | 1,710,106 | 0.0046 | 0.9954 | 96.32 |
| 11.5 | 1,543,384,649 | 2,481,865 | 0.0016 | 0.9984 | 95.87 |
| 12.5 | 1,574,343,592 | 337,101 | 0.0002 | 0.9998 | 95.72 |
| 13.5 | 1,568,256,887 | 1,562,570 | 0.0010 | 0.9990 | 95.70 |
| 14.5 | 1,592,773,075 | 1,331,389 | 0.0008 | 0.9992 | 95.60 |
| 15.5 | 1,616,505,502 | 189,702 | 0.0001 | 0.9999 | 95.52 |
| 16.5 | 1,610,253,100 | 781,613 | 0.0005 | 0.9995 | 95.51 |
| 17.5 | 1,619,132,555 | 963,720 | 0.0006 | 0.9994 | 95.46 |
| 18.5 | 1,625,599,942 | 1,680,000 | 0.0010 | 0.9990 | 95.41 |
| 19.5 | 1,639,846,793 | 3,836,728 | 0.0023 | 0.9977 | 95.31 |
| 20.5 | 1,639,109,845 | 2,767,334 | 0.0017 | 0.9983 | 95.08 |
| 21.5 | 1,685,471,729 | 5,065,875 | 0.0030 | 0.9970 | 94.92 |
| 22.5 | 1,661,425,605 | 7,862,994 | 0.0047 | 0.9953 | 94.64 |
| 23.5 | 1,732,092,056 | 3,056,495 | 0.0018 | 0.9982 | 94.19 |
| 24.5 | 1,696,753,428 | 1,920,751 | 0.0011 | 0.9989 | 94.02 |
| 25.5 | 1,685,498,573 | 1,935,240 | 0.0011 | 0.9989 | 93.92 |
| 26.5 | 1,650,373,822 | 4,208,278 | 0.0025 | 0.9975 | 93.81 |
| 27.5 | 1,970,259,139 | 5,190,928 | 0.0026 | 0.9974 | 93.57 |
| 28.5 | 1,954,681,217 | 16,792,121 | 0.0086 | 0.9914 | 93.32 |
| 29.5 | 1,892,219,020 | 3,402,688 | 0.0018 | 0.9982 | 92.52 |
| 30.5 | 1,838,336,163 | 6,706,516 | 0.0036 | 0.9964 | 92.36 |
| 31.5 | 336,054,484 | 1,352,269 | 0.0040 | 0.9960 | 92.02 |
| 32.5 | 300,291,900 | 2,135,882 | 0.0071 | 0.9929 | 91.65 |
| 33.5 | 291,059,161 | 2,422,740 | 0.0083 | 0.9917 | 91.00 |
| 34.5 | 265,602,134 | 1,349,824 | 0.0051 | 0.9949 | 90.24 |
| 35.5 | 233,172,301 | 993,910 | 0.0043 | 0.9957 | 89.78 |
| 36.5 | 230,318,958 | 1,774,912 | 0.0077 | 0.9923 | 89.40 |
| 37.5 | 228,464,232 | 1,289,639 | 0.0056 | 0.9944 | 88.71 |
| 38.5 | 212,342,798 | 2,594,822 | 0.0122 | 0.9878 | 88.21 |

DUKE ENERGY PROGRESS

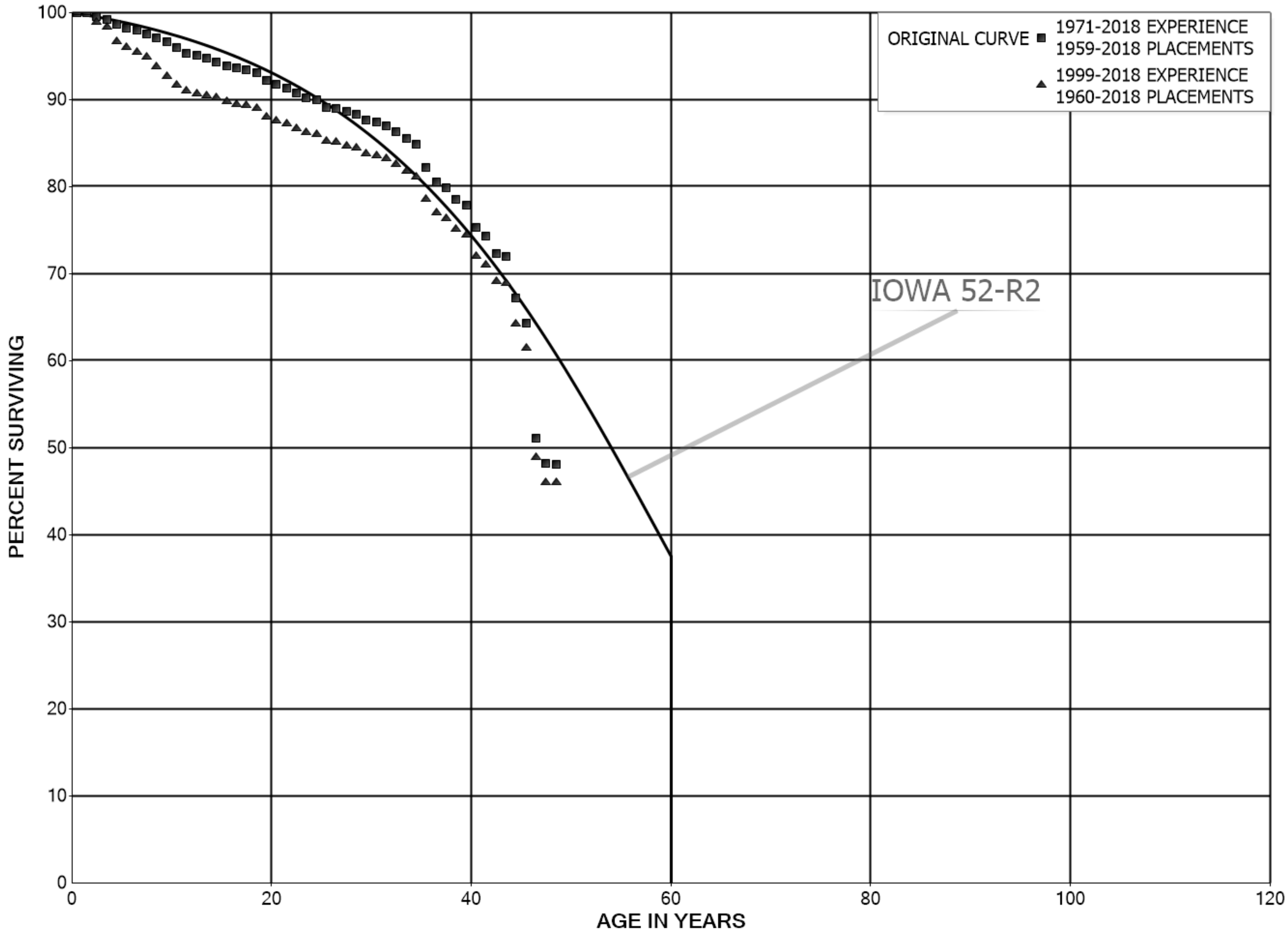
ACCOUNT 321 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 210,669,298 | 1,826,109 | 0.0087 | 0.9913 | 87.13 |
| 40.5 | 205,945,569 | 19,051,897 | 0.0925 | 0.9075 | 86.38 |
| 41.5 | 129,497,071 | 666,409 | 0.0051 | 0.9949 | 78.39 |
| 42.5 | 125,492,175 | 1,668,385 | 0.0133 | 0.9867 | 77.98 |
| 43.5 | 18,643,582 | 38,920 | 0.0021 | 0.9979 | 76.95 |
| 44.5 | 18,538,285 | 718,787 | 0.0388 | 0.9612 | 76.78 |
| 45.5 | 17,800,074 | 751,953 | 0.0422 | 0.9578 | 73.81 |
| 46.5 | 16,787,293 | 99,789 | 0.0059 | 0.9941 | 70.69 |
| 47.5 | 2,734 | | 0.0000 | 1.0000 | 70.27 |
| 48.5 | 2,797 | | 0.0000 | 1.0000 | 70.27 |
| 49.5 | 2,612 | | 0.0000 | 1.0000 | 70.27 |
| 50.5 | 3,606 | | 0.0000 | 1.0000 | 70.27 |
| 51.5 | 1,999 | | 0.0000 | 1.0000 | 70.27 |
| 52.5 | 3,584,946 | | 0.0000 | 1.0000 | 70.27 |
| 53.5 | 4,925,264 | | 0.0000 | 1.0000 | 70.27 |
| 54.5 | 4,925,264 | 46,627 | 0.0095 | 0.9905 | 70.27 |
| 55.5 | 4,877,208 | 2,485 | 0.0005 | 0.9995 | 69.60 |
| 56.5 | 4,874,724 | 155,707 | 0.0319 | 0.9681 | 69.57 |
| 57.5 | 4,719,016 | 9,161 | 0.0019 | 0.9981 | 67.35 |
| 58.5 | | | | | 67.22 |

DUKE ENERGY PROGRESS
ACCOUNT 322 REACTOR PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 322 REACTOR PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 2,802,857,132 | 492,368 | 0.0002 | 0.9998 | 100.00 |
| 0.5 | 2,538,715,236 | 822,193 | 0.0003 | 0.9997 | 99.98 |
| 1.5 | 2,443,226,738 | 10,592,067 | 0.0043 | 0.9957 | 99.95 |
| 2.5 | 2,366,005,507 | 8,057,456 | 0.0034 | 0.9966 | 99.52 |
| 3.5 | 2,218,513,560 | 13,465,485 | 0.0061 | 0.9939 | 99.18 |
| 4.5 | 2,177,667,588 | 8,577,533 | 0.0039 | 0.9961 | 98.58 |
| 5.5 | 2,049,179,093 | 4,745,452 | 0.0023 | 0.9977 | 98.19 |
| 6.5 | 1,946,019,539 | 8,345,298 | 0.0043 | 0.9957 | 97.96 |
| 7.5 | 1,888,716,714 | 8,355,693 | 0.0044 | 0.9956 | 97.54 |
| 8.5 | 1,799,180,599 | 8,354,070 | 0.0046 | 0.9954 | 97.11 |
| 9.5 | 1,768,474,606 | 13,458,061 | 0.0076 | 0.9924 | 96.66 |
| 10.5 | 1,742,678,265 | 12,539,615 | 0.0072 | 0.9928 | 95.92 |
| 11.5 | 1,705,686,759 | 3,793,913 | 0.0022 | 0.9978 | 95.23 |
| 12.5 | 1,696,378,055 | 5,058,245 | 0.0030 | 0.9970 | 95.02 |
| 13.5 | 1,638,710,646 | 8,689,384 | 0.0053 | 0.9947 | 94.74 |
| 14.5 | 1,611,605,532 | 6,949,772 | 0.0043 | 0.9957 | 94.23 |
| 15.5 | 1,584,112,272 | 4,331,338 | 0.0027 | 0.9973 | 93.83 |
| 16.5 | 1,561,949,571 | 2,373,896 | 0.0015 | 0.9985 | 93.57 |
| 17.5 | 1,377,281,727 | 5,595,722 | 0.0041 | 0.9959 | 93.43 |
| 18.5 | 1,364,629,414 | 12,518,935 | 0.0092 | 0.9908 | 93.05 |
| 19.5 | 1,350,453,525 | 7,095,230 | 0.0053 | 0.9947 | 92.20 |
| 20.5 | 1,350,815,463 | 6,864,098 | 0.0051 | 0.9949 | 91.71 |
| 21.5 | 1,304,941,697 | 7,970,169 | 0.0061 | 0.9939 | 91.25 |
| 22.5 | 1,282,777,983 | 7,630,579 | 0.0059 | 0.9941 | 90.69 |
| 23.5 | 1,256,996,965 | 2,922,787 | 0.0023 | 0.9977 | 90.15 |
| 24.5 | 1,174,459,221 | 10,834,573 | 0.0092 | 0.9908 | 89.94 |
| 25.5 | 1,161,853,405 | 1,785,191 | 0.0015 | 0.9985 | 89.11 |
| 26.5 | 1,146,170,607 | 4,850,135 | 0.0042 | 0.9958 | 88.97 |
| 27.5 | 1,255,493,402 | 4,445,004 | 0.0035 | 0.9965 | 88.60 |
| 28.5 | 1,232,339,247 | 8,999,585 | 0.0073 | 0.9927 | 88.28 |
| 29.5 | 1,199,305,248 | 3,096,531 | 0.0026 | 0.9974 | 87.64 |
| 30.5 | 1,168,066,322 | 5,381,539 | 0.0046 | 0.9954 | 87.41 |
| 31.5 | 531,136,380 | 4,232,723 | 0.0080 | 0.9920 | 87.01 |
| 32.5 | 518,888,764 | 4,595,245 | 0.0089 | 0.9911 | 86.32 |
| 33.5 | 458,769,448 | 3,854,658 | 0.0084 | 0.9916 | 85.55 |
| 34.5 | 277,935,683 | 8,882,348 | 0.0320 | 0.9680 | 84.83 |
| 35.5 | 235,775,008 | 4,634,409 | 0.0197 | 0.9803 | 82.12 |
| 36.5 | 228,255,776 | 1,933,352 | 0.0085 | 0.9915 | 80.51 |
| 37.5 | 242,274,485 | 3,875,267 | 0.0160 | 0.9840 | 79.82 |
| 38.5 | 232,144,756 | 2,039,620 | 0.0088 | 0.9912 | 78.55 |

DUKE ENERGY PROGRESS

ACCOUNT 322 REACTOR PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 234,873,225 | 7,599,317 | 0.0324 | 0.9676 | 77.86 |
| 40.5 | 222,420,042 | 3,245,010 | 0.0146 | 0.9854 | 75.34 |
| 41.5 | 108,946,175 | 2,920,688 | 0.0268 | 0.9732 | 74.24 |
| 42.5 | 102,996,525 | 376,415 | 0.0037 | 0.9963 | 72.25 |
| 43.5 | 11,649,636 | 784,360 | 0.0673 | 0.9327 | 71.99 |
| 44.5 | 10,512,914 | 446,312 | 0.0425 | 0.9575 | 67.14 |
| 45.5 | 10,066,602 | 2,068,012 | 0.2054 | 0.7946 | 64.29 |
| 46.5 | 7,444,730 | 428,756 | 0.0576 | 0.9424 | 51.08 |
| 47.5 | 4,667 | 4 | 0.0009 | 0.9991 | 48.14 |
| 48.5 | | | | | 48.10 |
| 49.5 | | | | | |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | 58,520 | | 0.0000 | | |
| 53.5 | 65,078 | | 0.0000 | | |
| 54.5 | 65,078 | | 0.0000 | | |
| 55.5 | 65,078 | | 0.0000 | | |
| 56.5 | 65,078 | 58,520 | 0.8992 | | |
| 57.5 | 6,558 | 8 | 0.0012 | | |
| 58.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 322 REACTOR PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,162,042,019 | 492,368 | 0.0004 | 0.9996 | 100.00 |
| 0.5 | 996,546,687 | 494,515 | 0.0005 | 0.9995 | 99.96 |
| 1.5 | 952,460,793 | 10,212,015 | 0.0107 | 0.9893 | 99.91 |
| 2.5 | 893,567,787 | 5,248,330 | 0.0059 | 0.9941 | 98.84 |
| 3.5 | 781,262,848 | 12,869,522 | 0.0165 | 0.9835 | 98.26 |
| 4.5 | 821,669,525 | 5,778,892 | 0.0070 | 0.9930 | 96.64 |
| 5.5 | 726,196,584 | 3,876,008 | 0.0053 | 0.9947 | 95.96 |
| 6.5 | 668,041,995 | 4,543,537 | 0.0068 | 0.9932 | 95.45 |
| 7.5 | 665,012,170 | 7,756,517 | 0.0117 | 0.9883 | 94.80 |
| 8.5 | 607,182,473 | 6,935,807 | 0.0114 | 0.9886 | 93.69 |
| 9.5 | 613,351,759 | 6,906,906 | 0.0113 | 0.9887 | 92.62 |
| 10.5 | 628,467,568 | 4,414,579 | 0.0070 | 0.9930 | 91.58 |
| 11.5 | 1,162,691,008 | 3,639,160 | 0.0031 | 0.9969 | 90.93 |
| 12.5 | 1,163,157,743 | 2,771,065 | 0.0024 | 0.9976 | 90.65 |
| 13.5 | 1,157,793,657 | 3,300,142 | 0.0029 | 0.9971 | 90.43 |
| 14.5 | 1,307,230,068 | 6,886,814 | 0.0053 | 0.9947 | 90.18 |
| 15.5 | 1,312,562,944 | 3,803,351 | 0.0029 | 0.9971 | 89.70 |
| 16.5 | 1,295,056,359 | 1,975,559 | 0.0015 | 0.9985 | 89.44 |
| 17.5 | 1,116,019,320 | 4,018,359 | 0.0036 | 0.9964 | 89.30 |
| 18.5 | 1,112,703,173 | 12,486,765 | 0.0112 | 0.9888 | 88.98 |
| 19.5 | 1,108,418,333 | 5,486,272 | 0.0049 | 0.9951 | 87.98 |
| 20.5 | 1,115,172,399 | 4,688,355 | 0.0042 | 0.9958 | 87.55 |
| 21.5 | 1,184,739,276 | 7,970,169 | 0.0067 | 0.9933 | 87.18 |
| 22.5 | 1,165,413,790 | 5,926,225 | 0.0051 | 0.9949 | 86.59 |
| 23.5 | 1,239,038,774 | 2,666,514 | 0.0022 | 0.9978 | 86.15 |
| 24.5 | 1,157,188,293 | 10,834,573 | 0.0094 | 0.9906 | 85.97 |
| 25.5 | 1,144,637,019 | 1,785,191 | 0.0016 | 0.9984 | 85.16 |
| 26.5 | 1,130,240,280 | 4,850,135 | 0.0043 | 0.9957 | 85.03 |
| 27.5 | 1,255,400,227 | 4,445,004 | 0.0035 | 0.9965 | 84.67 |
| 28.5 | 1,232,246,072 | 8,999,585 | 0.0073 | 0.9927 | 84.37 |
| 29.5 | 1,199,305,248 | 3,096,531 | 0.0026 | 0.9974 | 83.75 |
| 30.5 | 1,168,066,322 | 5,381,539 | 0.0046 | 0.9954 | 83.53 |
| 31.5 | 531,136,380 | 4,232,723 | 0.0080 | 0.9920 | 83.15 |
| 32.5 | 518,888,764 | 4,595,245 | 0.0089 | 0.9911 | 82.49 |
| 33.5 | 458,769,448 | 3,854,658 | 0.0084 | 0.9916 | 81.76 |
| 34.5 | 277,935,683 | 8,882,348 | 0.0320 | 0.9680 | 81.07 |
| 35.5 | 235,775,008 | 4,634,409 | 0.0197 | 0.9803 | 78.48 |
| 36.5 | 228,255,776 | 1,933,352 | 0.0085 | 0.9915 | 76.94 |
| 37.5 | 242,274,485 | 3,875,267 | 0.0160 | 0.9840 | 76.28 |
| 38.5 | 232,144,756 | 2,039,620 | 0.0088 | 0.9912 | 75.06 |

DUKE ENERGY PROGRESS

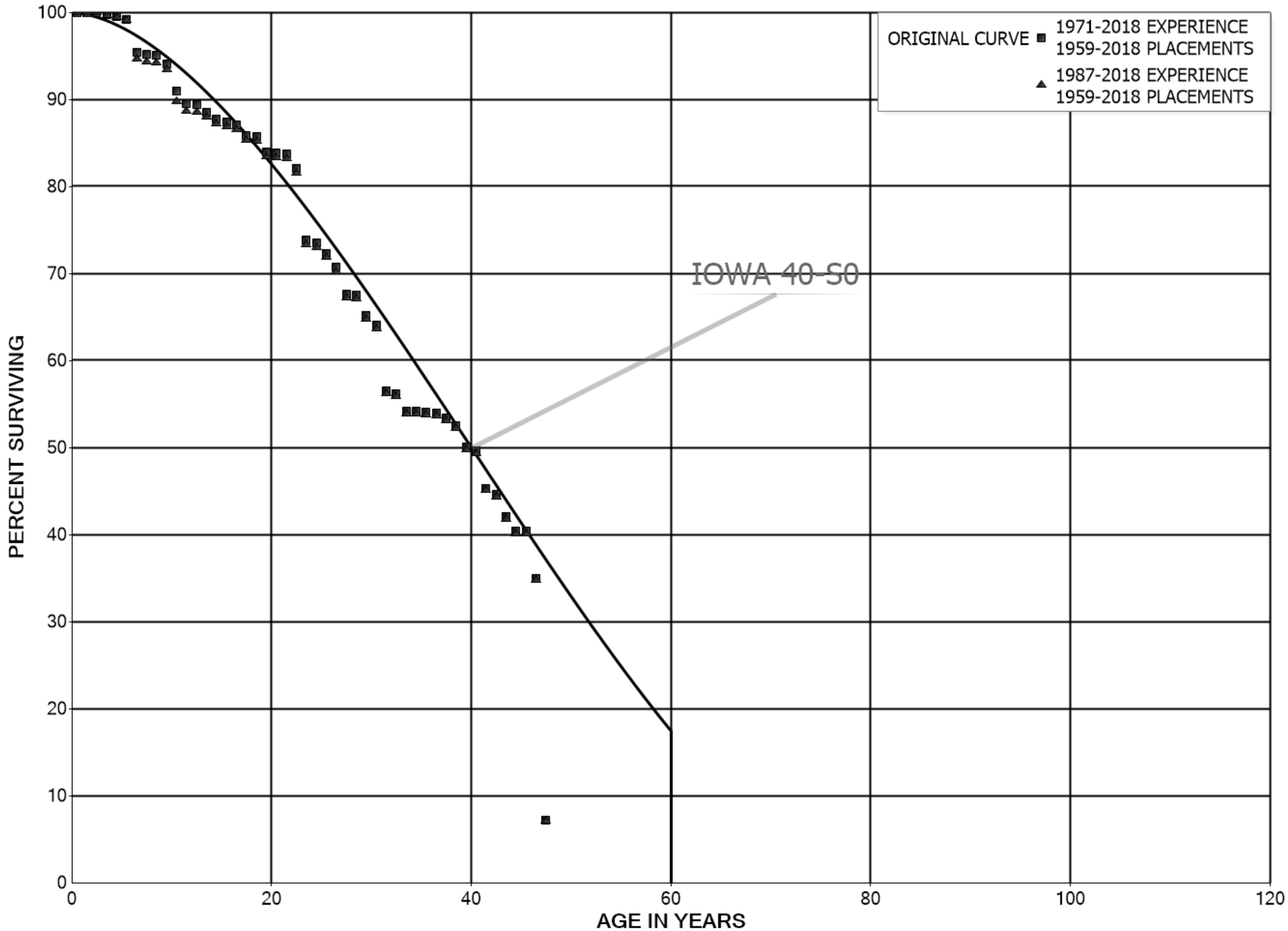
ACCOUNT 322 REACTOR PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 234,873,225 | 7,599,317 | 0.0324 | 0.9676 | 74.40 |
| 40.5 | 222,420,042 | 3,245,010 | 0.0146 | 0.9854 | 72.00 |
| 41.5 | 108,946,175 | 2,920,688 | 0.0268 | 0.9732 | 70.95 |
| 42.5 | 102,996,525 | 376,415 | 0.0037 | 0.9963 | 69.04 |
| 43.5 | 11,649,636 | 784,360 | 0.0673 | 0.9327 | 68.79 |
| 44.5 | 10,512,914 | 446,312 | 0.0425 | 0.9575 | 64.16 |
| 45.5 | 10,066,602 | 2,068,012 | 0.2054 | 0.7946 | 61.44 |
| 46.5 | 7,444,730 | 428,756 | 0.0576 | 0.9424 | 48.82 |
| 47.5 | 4,667 | 4 | 0.0009 | 0.9991 | 46.00 |
| 48.5 | | | | | 45.96 |
| 49.5 | | | | | |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | 58,520 | | 0.0000 | | |
| 53.5 | 65,078 | | 0.0000 | | |
| 54.5 | 65,078 | | 0.0000 | | |
| 55.5 | 65,078 | | 0.0000 | | |
| 56.5 | 65,078 | 58,520 | 0.8992 | | |
| 57.5 | 6,558 | 8 | 0.0012 | | |
| 58.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 323 TURBOGENERATOR UNITS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 323 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,465,506,031 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 1,122,222,099 | 172,635 | 0.0002 | 0.9998 | 100.00 |
| 1.5 | 1,000,214,464 | 260,168 | 0.0003 | 0.9997 | 99.98 |
| 2.5 | 944,935,394 | 2,532,606 | 0.0027 | 0.9973 | 99.96 |
| 3.5 | 910,956,143 | 1,750,614 | 0.0019 | 0.9981 | 99.69 |
| 4.5 | 889,101,696 | 2,853,754 | 0.0032 | 0.9968 | 99.50 |
| 5.5 | 856,016,438 | 32,370,994 | 0.0378 | 0.9622 | 99.18 |
| 6.5 | 704,380,537 | 2,029,307 | 0.0029 | 0.9971 | 95.43 |
| 7.5 | 700,070,711 | 378,322 | 0.0005 | 0.9995 | 95.15 |
| 8.5 | 596,082,097 | 6,169,099 | 0.0103 | 0.9897 | 95.10 |
| 9.5 | 586,810,533 | 20,106,235 | 0.0343 | 0.9657 | 94.12 |
| 10.5 | 550,493,369 | 8,385,295 | 0.0152 | 0.9848 | 90.89 |
| 11.5 | 538,177,735 | 707,910 | 0.0013 | 0.9987 | 89.51 |
| 12.5 | 539,166,396 | 5,664,654 | 0.0105 | 0.9895 | 89.39 |
| 13.5 | 521,160,637 | 4,004,481 | 0.0077 | 0.9923 | 88.45 |
| 14.5 | 502,829,419 | 2,297,077 | 0.0046 | 0.9954 | 87.77 |
| 15.5 | 487,565,700 | 1,686,056 | 0.0035 | 0.9965 | 87.37 |
| 16.5 | 460,052,047 | 6,300,133 | 0.0137 | 0.9863 | 87.07 |
| 17.5 | 430,174,686 | 799,687 | 0.0019 | 0.9981 | 85.88 |
| 18.5 | 423,399,633 | 8,851,704 | 0.0209 | 0.9791 | 85.72 |
| 19.5 | 421,671,024 | 286,683 | 0.0007 | 0.9993 | 83.93 |
| 20.5 | 423,115,254 | 890,195 | 0.0021 | 0.9979 | 83.87 |
| 21.5 | 419,809,346 | 8,269,510 | 0.0197 | 0.9803 | 83.69 |
| 22.5 | 398,946,582 | 39,918,729 | 0.1001 | 0.8999 | 82.04 |
| 23.5 | 332,067,354 | 1,593,849 | 0.0048 | 0.9952 | 73.83 |
| 24.5 | 320,185,164 | 5,250,066 | 0.0164 | 0.9836 | 73.48 |
| 25.5 | 314,350,800 | 6,838,181 | 0.0218 | 0.9782 | 72.27 |
| 26.5 | 304,218,741 | 13,303,263 | 0.0437 | 0.9563 | 70.70 |
| 27.5 | 326,410,936 | 665,456 | 0.0020 | 0.9980 | 67.61 |
| 28.5 | 325,943,335 | 11,044,845 | 0.0339 | 0.9661 | 67.47 |
| 29.5 | 309,535,155 | 5,549,693 | 0.0179 | 0.9821 | 65.19 |
| 30.5 | 301,321,832 | 35,312,169 | 0.1172 | 0.8828 | 64.02 |
| 31.5 | 125,973,445 | 696,729 | 0.0055 | 0.9945 | 56.52 |
| 32.5 | 119,312,377 | 4,204,753 | 0.0352 | 0.9648 | 56.20 |
| 33.5 | 115,931,710 | 56,932 | 0.0005 | 0.9995 | 54.22 |
| 34.5 | 97,608,099 | 174,536 | 0.0018 | 0.9982 | 54.20 |
| 35.5 | 80,146,180 | 148,037 | 0.0018 | 0.9982 | 54.10 |
| 36.5 | 72,498,718 | 825,631 | 0.0114 | 0.9886 | 54.00 |
| 37.5 | 70,645,410 | 1,127,546 | 0.0160 | 0.9840 | 53.38 |
| 38.5 | 68,582,811 | 3,240,862 | 0.0473 | 0.9527 | 52.53 |

DUKE ENERGY PROGRESS

ACCOUNT 323 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 66,873,242 | 509,200 | 0.0076 | 0.9924 | 50.05 |
| 40.5 | 65,108,538 | 5,678,038 | 0.0872 | 0.9128 | 49.67 |
| 41.5 | 37,066,934 | 590,352 | 0.0159 | 0.9841 | 45.34 |
| 42.5 | 36,476,369 | 2,091,497 | 0.0573 | 0.9427 | 44.61 |
| 43.5 | 11,642,760 | 468,780 | 0.0403 | 0.9597 | 42.06 |
| 44.5 | 10,961,013 | | 0.0000 | 1.0000 | 40.36 |
| 45.5 | 10,961,013 | 1,460,675 | 0.1333 | 0.8667 | 40.36 |
| 46.5 | 8,450,812 | 6,727,728 | 0.7961 | 0.2039 | 34.98 |
| 47.5 | | | | | 7.13 |
| 48.5 | | | | | |
| 49.5 | | | | | |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | | | | | |
| 53.5 | 146,163 | | 0.0000 | | |
| 54.5 | 146,163 | | 0.0000 | | |
| 55.5 | 146,163 | | 0.0000 | | |
| 56.5 | 146,163 | | 0.0000 | | |
| 57.5 | 146,163 | | 0.0000 | | |
| 58.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 323 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1987-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,269,792,970 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 932,050,837 | 172,635 | 0.0002 | 0.9998 | 100.00 |
| 1.5 | 813,867,917 | 260,168 | 0.0003 | 0.9997 | 99.98 |
| 2.5 | 778,753,293 | 2,532,600 | 0.0033 | 0.9967 | 99.95 |
| 3.5 | 758,796,373 | 1,750,614 | 0.0023 | 0.9977 | 99.62 |
| 4.5 | 741,486,862 | 2,787,758 | 0.0038 | 0.9962 | 99.39 |
| 5.5 | 722,238,107 | 32,317,234 | 0.0447 | 0.9553 | 99.02 |
| 6.5 | 575,932,531 | 1,998,694 | 0.0035 | 0.9965 | 94.59 |
| 7.5 | 572,666,257 | 356,340 | 0.0006 | 0.9994 | 94.26 |
| 8.5 | 481,352,638 | 4,103,627 | 0.0085 | 0.9915 | 94.20 |
| 9.5 | 515,555,891 | 20,083,344 | 0.0390 | 0.9610 | 93.40 |
| 10.5 | 479,276,521 | 6,269,832 | 0.0131 | 0.9869 | 89.76 |
| 11.5 | 512,860,357 | 588,520 | 0.0011 | 0.9989 | 88.59 |
| 12.5 | 514,472,678 | 3,387,329 | 0.0066 | 0.9934 | 88.49 |
| 13.5 | 498,744,244 | 4,004,481 | 0.0080 | 0.9920 | 87.90 |
| 14.5 | 481,512,345 | 2,297,077 | 0.0048 | 0.9952 | 87.20 |
| 15.5 | 487,565,700 | 1,686,056 | 0.0035 | 0.9965 | 86.78 |
| 16.5 | 460,052,047 | 6,300,133 | 0.0137 | 0.9863 | 86.48 |
| 17.5 | 430,174,686 | 799,687 | 0.0019 | 0.9981 | 85.30 |
| 18.5 | 423,399,633 | 8,851,704 | 0.0209 | 0.9791 | 85.14 |
| 19.5 | 421,671,024 | 286,683 | 0.0007 | 0.9993 | 83.36 |
| 20.5 | 423,115,254 | 890,195 | 0.0021 | 0.9979 | 83.30 |
| 21.5 | 419,809,346 | 8,269,510 | 0.0197 | 0.9803 | 83.13 |
| 22.5 | 398,946,582 | 39,918,729 | 0.1001 | 0.8999 | 81.49 |
| 23.5 | 332,067,354 | 1,593,849 | 0.0048 | 0.9952 | 73.34 |
| 24.5 | 320,185,164 | 5,250,066 | 0.0164 | 0.9836 | 72.98 |
| 25.5 | 314,350,800 | 6,838,181 | 0.0218 | 0.9782 | 71.79 |
| 26.5 | 304,218,741 | 13,303,263 | 0.0437 | 0.9563 | 70.23 |
| 27.5 | 326,410,936 | 665,456 | 0.0020 | 0.9980 | 67.15 |
| 28.5 | 325,943,335 | 11,044,845 | 0.0339 | 0.9661 | 67.02 |
| 29.5 | 309,535,155 | 5,549,693 | 0.0179 | 0.9821 | 64.75 |
| 30.5 | 301,321,832 | 35,312,169 | 0.1172 | 0.8828 | 63.59 |
| 31.5 | 125,973,445 | 696,729 | 0.0055 | 0.9945 | 56.13 |
| 32.5 | 119,312,377 | 4,204,753 | 0.0352 | 0.9648 | 55.82 |
| 33.5 | 115,931,710 | 56,932 | 0.0005 | 0.9995 | 53.86 |
| 34.5 | 97,608,099 | 174,536 | 0.0018 | 0.9982 | 53.83 |
| 35.5 | 80,146,180 | 148,037 | 0.0018 | 0.9982 | 53.73 |
| 36.5 | 72,498,718 | 825,631 | 0.0114 | 0.9886 | 53.63 |
| 37.5 | 70,645,410 | 1,127,546 | 0.0160 | 0.9840 | 53.02 |
| 38.5 | 68,582,811 | 3,240,862 | 0.0473 | 0.9527 | 52.18 |

DUKE ENERGY PROGRESS

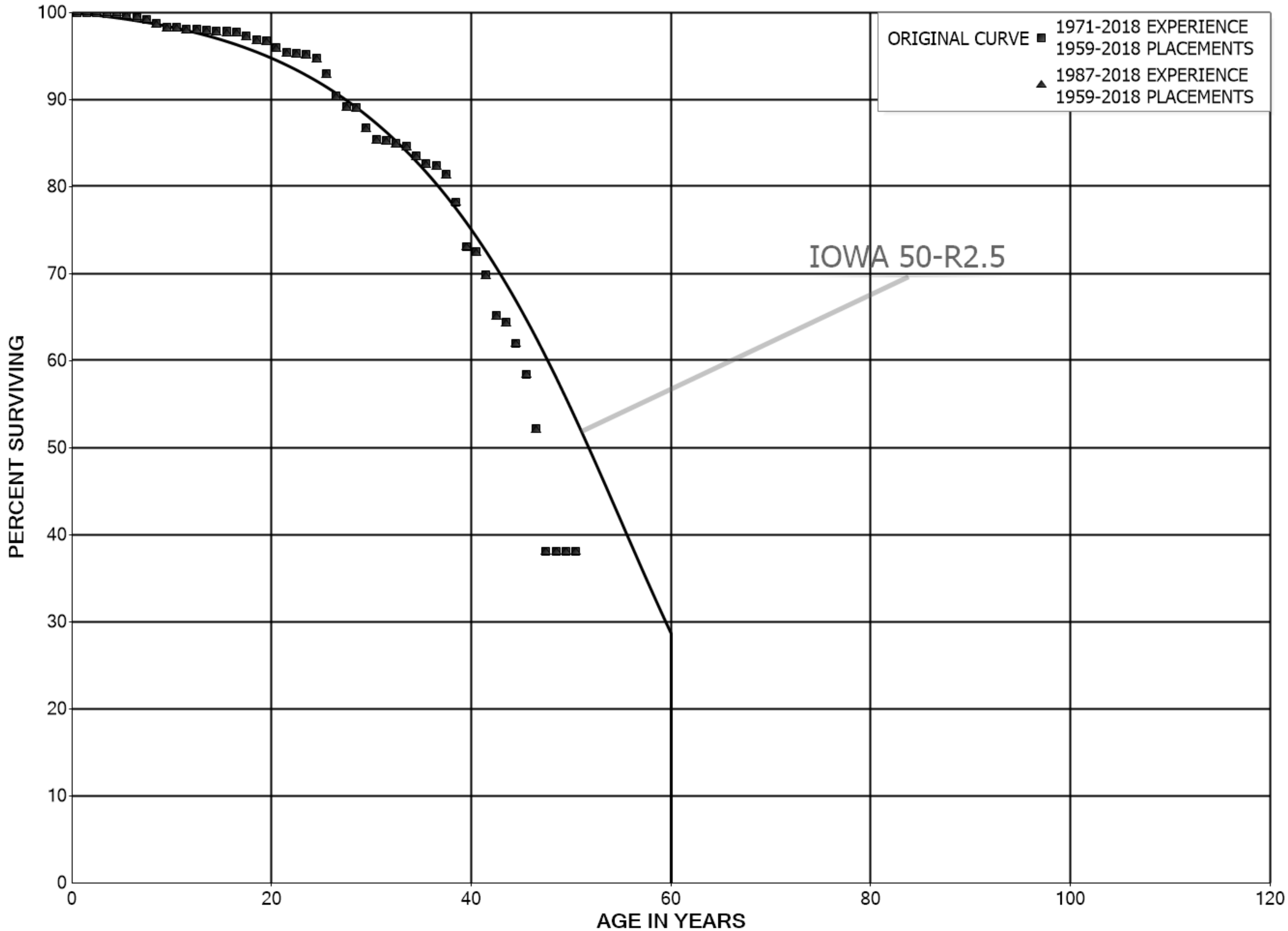
ACCOUNT 323 TURBOGENERATOR UNITS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1987-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 66,873,242 | 509,200 | 0.0076 | 0.9924 | 49.71 |
| 40.5 | 65,108,538 | 5,678,038 | 0.0872 | 0.9128 | 49.33 |
| 41.5 | 37,066,934 | 590,352 | 0.0159 | 0.9841 | 45.03 |
| 42.5 | 36,476,369 | 2,091,497 | 0.0573 | 0.9427 | 44.31 |
| 43.5 | 11,642,760 | 468,780 | 0.0403 | 0.9597 | 41.77 |
| 44.5 | 10,961,013 | | 0.0000 | 1.0000 | 40.09 |
| 45.5 | 10,961,013 | 1,460,675 | 0.1333 | 0.8667 | 40.09 |
| 46.5 | 8,450,812 | 6,727,728 | 0.7961 | 0.2039 | 34.75 |
| 47.5 | | | | | 7.08 |
| 48.5 | | | | | |
| 49.5 | | | | | |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | | | | | |
| 53.5 | 146,163 | | 0.0000 | | |
| 54.5 | 146,163 | | 0.0000 | | |
| 55.5 | 146,163 | | 0.0000 | | |
| 56.5 | 146,163 | | 0.0000 | | |
| 57.5 | 146,163 | | 0.0000 | | |
| 58.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,639,788,051 | 27,406 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 1,192,017,390 | 736,317 | 0.0006 | 0.9994 | 100.00 |
| 1.5 | 1,150,473,821 | 311,313 | 0.0003 | 0.9997 | 99.94 |
| 2.5 | 1,096,817,373 | 315,255 | 0.0003 | 0.9997 | 99.91 |
| 3.5 | 971,015,542 | 493,671 | 0.0005 | 0.9995 | 99.88 |
| 4.5 | 885,912,061 | 2,129,177 | 0.0024 | 0.9976 | 99.83 |
| 5.5 | 822,115,594 | 1,246,250 | 0.0015 | 0.9985 | 99.59 |
| 6.5 | 783,412,800 | 2,104,650 | 0.0027 | 0.9973 | 99.44 |
| 7.5 | 769,900,373 | 3,815,611 | 0.0050 | 0.9950 | 99.17 |
| 8.5 | 693,764,450 | 2,601,162 | 0.0037 | 0.9963 | 98.68 |
| 9.5 | 690,311,017 | 506,532 | 0.0007 | 0.9993 | 98.31 |
| 10.5 | 686,588,428 | 1,439,545 | 0.0021 | 0.9979 | 98.24 |
| 11.5 | 681,351,493 | 102,833 | 0.0002 | 0.9998 | 98.03 |
| 12.5 | 679,499,538 | 497,805 | 0.0007 | 0.9993 | 98.02 |
| 13.5 | 673,365,458 | 468,084 | 0.0007 | 0.9993 | 97.95 |
| 14.5 | 671,598,350 | 617,337 | 0.0009 | 0.9991 | 97.88 |
| 15.5 | 670,507,399 | 400,858 | 0.0006 | 0.9994 | 97.79 |
| 16.5 | 668,166,179 | 2,880,780 | 0.0043 | 0.9957 | 97.73 |
| 17.5 | 663,295,174 | 2,931,373 | 0.0044 | 0.9956 | 97.31 |
| 18.5 | 658,563,233 | 1,205,111 | 0.0018 | 0.9982 | 96.88 |
| 19.5 | 657,585,506 | 4,711,286 | 0.0072 | 0.9928 | 96.70 |
| 20.5 | 658,292,102 | 4,439,565 | 0.0067 | 0.9933 | 96.01 |
| 21.5 | 651,111,597 | 238,657 | 0.0004 | 0.9996 | 95.36 |
| 22.5 | 649,945,681 | 1,329,211 | 0.0020 | 0.9980 | 95.33 |
| 23.5 | 643,372,331 | 2,892,386 | 0.0045 | 0.9955 | 95.13 |
| 24.5 | 605,561,228 | 11,377,877 | 0.0188 | 0.9812 | 94.70 |
| 25.5 | 593,468,478 | 16,190,089 | 0.0273 | 0.9727 | 92.92 |
| 26.5 | 576,615,937 | 7,763,497 | 0.0135 | 0.9865 | 90.39 |
| 27.5 | 686,390,052 | 1,107,307 | 0.0016 | 0.9984 | 89.17 |
| 28.5 | 683,718,743 | 17,619,165 | 0.0258 | 0.9742 | 89.03 |
| 29.5 | 659,844,732 | 9,991,461 | 0.0151 | 0.9849 | 86.73 |
| 30.5 | 639,260,724 | 1,264,001 | 0.0020 | 0.9980 | 85.42 |
| 31.5 | 109,228,037 | 353,858 | 0.0032 | 0.9968 | 85.25 |
| 32.5 | 93,924,232 | 431,286 | 0.0046 | 0.9954 | 84.97 |
| 33.5 | 92,941,644 | 1,154,098 | 0.0124 | 0.9876 | 84.58 |
| 34.5 | 84,765,461 | 982,415 | 0.0116 | 0.9884 | 83.53 |
| 35.5 | 83,900,029 | 171,181 | 0.0020 | 0.9980 | 82.57 |
| 36.5 | 83,537,198 | 1,039,497 | 0.0124 | 0.9876 | 82.40 |
| 37.5 | 88,031,263 | 3,426,879 | 0.0389 | 0.9611 | 81.37 |
| 38.5 | 82,790,322 | 5,418,344 | 0.0654 | 0.9346 | 78.20 |

DUKE ENERGY PROGRESS

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 81,953,659 | 642,177 | 0.0078 | 0.9922 | 73.09 |
| 40.5 | 80,838,200 | 3,044,487 | 0.0377 | 0.9623 | 72.51 |
| 41.5 | 53,281,314 | 3,528,628 | 0.0662 | 0.9338 | 69.78 |
| 42.5 | 49,620,728 | 612,324 | 0.0123 | 0.9877 | 65.16 |
| 43.5 | 7,157,799 | 264,548 | 0.0370 | 0.9630 | 64.36 |
| 44.5 | 6,707,304 | 389,529 | 0.0581 | 0.9419 | 61.98 |
| 45.5 | 6,318,902 | 676,892 | 0.1071 | 0.8929 | 58.38 |
| 46.5 | 5,642,011 | 1,523,271 | 0.2700 | 0.7300 | 52.13 |
| 47.5 | 1,127 | | 0.0000 | 1.0000 | 38.05 |
| 48.5 | 1,127 | | 0.0000 | 1.0000 | 38.05 |
| 49.5 | 1,127 | 1 | 0.0005 | 0.9995 | 38.05 |
| 50.5 | | | | | 38.04 |
| 51.5 | 213 | | 0.0000 | | |
| 52.5 | 213 | | 0.0000 | | |
| 53.5 | 50,660 | | 0.0000 | | |
| 54.5 | 50,660 | | 0.0000 | | |
| 55.5 | 50,660 | 0 | 0.0000 | | |
| 56.5 | 50,447 | | 0.0000 | | |
| 57.5 | 50,447 | 28 | 0.0006 | | |
| 58.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1987-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,512,786,748 | 27,406 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 1,083,888,070 | 736,317 | 0.0007 | 0.9993 | 100.00 |
| 1.5 | 1,043,383,483 | 296,577 | 0.0003 | 0.9997 | 99.93 |
| 2.5 | 997,035,878 | 315,255 | 0.0003 | 0.9997 | 99.90 |
| 3.5 | 871,295,168 | 493,671 | 0.0006 | 0.9994 | 99.87 |
| 4.5 | 786,294,533 | 2,129,177 | 0.0027 | 0.9973 | 99.81 |
| 5.5 | 724,284,583 | 1,246,250 | 0.0017 | 0.9983 | 99.54 |
| 6.5 | 687,855,143 | 2,104,650 | 0.0031 | 0.9969 | 99.37 |
| 7.5 | 683,682,181 | 3,815,611 | 0.0056 | 0.9944 | 99.07 |
| 8.5 | 609,807,208 | 2,593,162 | 0.0043 | 0.9957 | 98.52 |
| 9.5 | 639,133,549 | 506,532 | 0.0008 | 0.9992 | 98.10 |
| 10.5 | 635,908,429 | 1,439,545 | 0.0023 | 0.9977 | 98.02 |
| 11.5 | 672,766,257 | 102,833 | 0.0002 | 0.9998 | 97.80 |
| 12.5 | 671,106,867 | 497,805 | 0.0007 | 0.9993 | 97.78 |
| 13.5 | 664,976,109 | 468,084 | 0.0007 | 0.9993 | 97.71 |
| 14.5 | 663,637,669 | 617,337 | 0.0009 | 0.9991 | 97.64 |
| 15.5 | 670,488,545 | 400,858 | 0.0006 | 0.9994 | 97.55 |
| 16.5 | 668,147,325 | 2,880,780 | 0.0043 | 0.9957 | 97.49 |
| 17.5 | 663,276,321 | 2,931,373 | 0.0044 | 0.9956 | 97.07 |
| 18.5 | 658,544,380 | 1,205,111 | 0.0018 | 0.9982 | 96.64 |
| 19.5 | 657,566,652 | 4,711,286 | 0.0072 | 0.9928 | 96.46 |
| 20.5 | 658,273,248 | 4,439,565 | 0.0067 | 0.9933 | 95.77 |
| 21.5 | 651,092,743 | 238,657 | 0.0004 | 0.9996 | 95.13 |
| 22.5 | 649,926,828 | 1,329,211 | 0.0020 | 0.9980 | 95.09 |
| 23.5 | 643,353,477 | 2,892,386 | 0.0045 | 0.9955 | 94.90 |
| 24.5 | 605,542,375 | 11,377,877 | 0.0188 | 0.9812 | 94.47 |
| 25.5 | 593,449,624 | 16,190,089 | 0.0273 | 0.9727 | 92.70 |
| 26.5 | 576,597,083 | 7,763,497 | 0.0135 | 0.9865 | 90.17 |
| 27.5 | 686,390,052 | 1,107,307 | 0.0016 | 0.9984 | 88.95 |
| 28.5 | 683,718,743 | 17,619,165 | 0.0258 | 0.9742 | 88.81 |
| 29.5 | 659,844,732 | 9,991,461 | 0.0151 | 0.9849 | 86.52 |
| 30.5 | 639,260,724 | 1,264,001 | 0.0020 | 0.9980 | 85.21 |
| 31.5 | 109,228,037 | 353,858 | 0.0032 | 0.9968 | 85.04 |
| 32.5 | 93,924,232 | 431,286 | 0.0046 | 0.9954 | 84.77 |
| 33.5 | 92,941,644 | 1,154,098 | 0.0124 | 0.9876 | 84.38 |
| 34.5 | 84,765,461 | 982,415 | 0.0116 | 0.9884 | 83.33 |
| 35.5 | 83,900,029 | 171,181 | 0.0020 | 0.9980 | 82.36 |
| 36.5 | 83,537,198 | 1,039,497 | 0.0124 | 0.9876 | 82.20 |
| 37.5 | 88,031,263 | 3,426,879 | 0.0389 | 0.9611 | 81.17 |
| 38.5 | 82,790,322 | 5,418,344 | 0.0654 | 0.9346 | 78.01 |

DUKE ENERGY PROGRESS

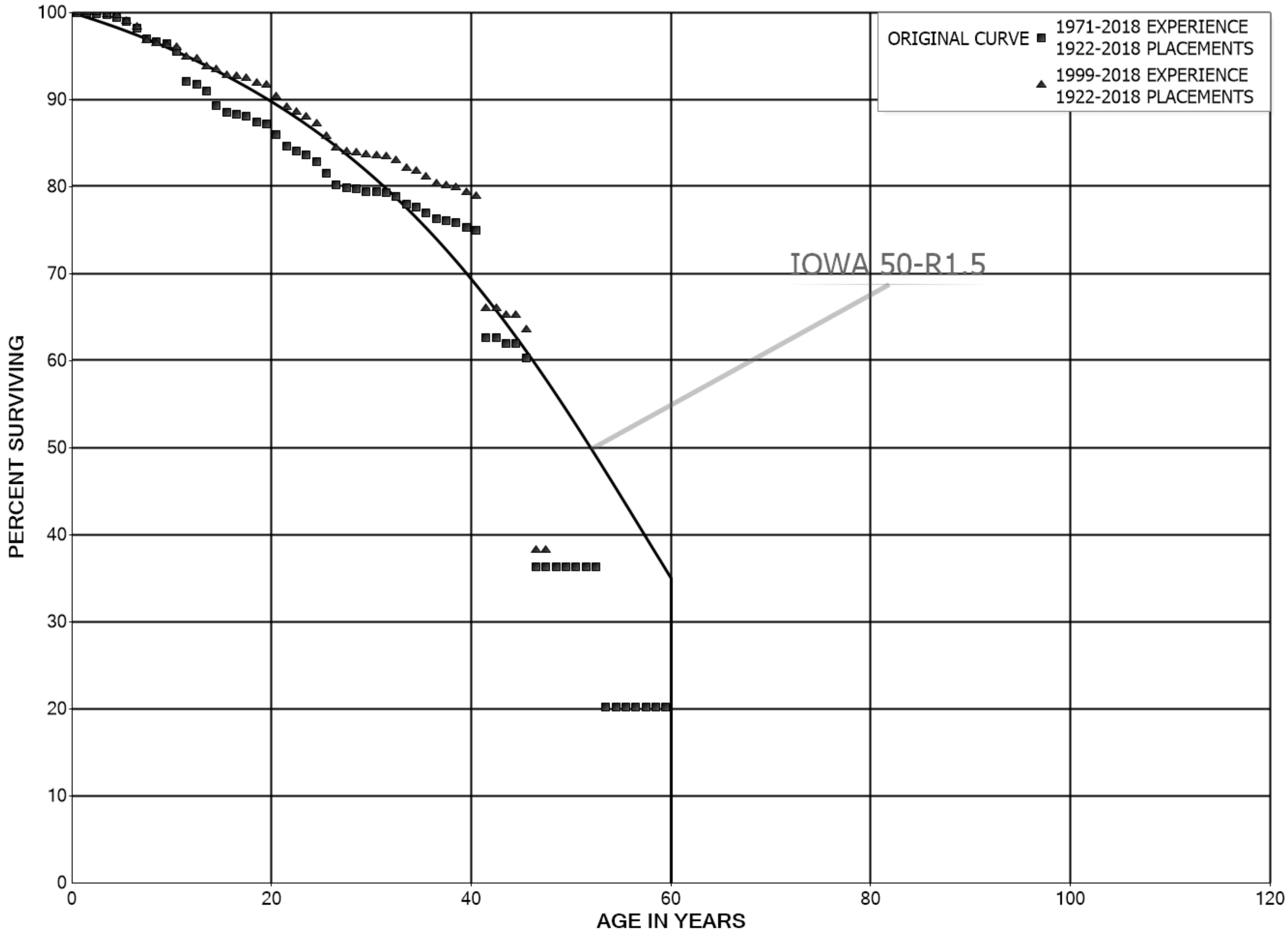
ACCOUNT 324 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1987-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 81,953,659 | 642,177 | 0.0078 | 0.9922 | 72.91 |
| 40.5 | 80,838,200 | 3,044,487 | 0.0377 | 0.9623 | 72.34 |
| 41.5 | 53,281,314 | 3,528,628 | 0.0662 | 0.9338 | 69.61 |
| 42.5 | 49,620,728 | 612,324 | 0.0123 | 0.9877 | 65.00 |
| 43.5 | 7,157,799 | 264,548 | 0.0370 | 0.9630 | 64.20 |
| 44.5 | 6,707,304 | 389,529 | 0.0581 | 0.9419 | 61.83 |
| 45.5 | 6,318,902 | 676,892 | 0.1071 | 0.8929 | 58.24 |
| 46.5 | 5,642,011 | 1,523,271 | 0.2700 | 0.7300 | 52.00 |
| 47.5 | 1,127 | | 0.0000 | 1.0000 | 37.96 |
| 48.5 | 1,127 | | 0.0000 | 1.0000 | 37.96 |
| 49.5 | 1,127 | 1 | 0.0005 | 0.9995 | 37.96 |
| 50.5 | | | | | 37.94 |
| 51.5 | 213 | | 0.0000 | | |
| 52.5 | 213 | | 0.0000 | | |
| 53.5 | 50,660 | | 0.0000 | | |
| 54.5 | 50,660 | | 0.0000 | | |
| 55.5 | 50,660 | 0 | 0.0000 | | |
| 56.5 | 50,447 | | 0.0000 | | |
| 57.5 | 50,447 | 28 | 0.0006 | | |
| 58.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 735,747,983 | 11,439 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 641,356,564 | 311,698 | 0.0005 | 0.9995 | 100.00 |
| 1.5 | 575,926,959 | 746,773 | 0.0013 | 0.9987 | 99.95 |
| 2.5 | 543,654,097 | 753,376 | 0.0014 | 0.9986 | 99.82 |
| 3.5 | 486,465,196 | 1,411,623 | 0.0029 | 0.9971 | 99.68 |
| 4.5 | 474,019,938 | 2,138,669 | 0.0045 | 0.9955 | 99.39 |
| 5.5 | 438,849,555 | 3,472,823 | 0.0079 | 0.9921 | 98.94 |
| 6.5 | 367,518,860 | 4,381,273 | 0.0119 | 0.9881 | 98.16 |
| 7.5 | 337,948,107 | 1,202,338 | 0.0036 | 0.9964 | 96.99 |
| 8.5 | 328,600,761 | 1,035,889 | 0.0032 | 0.9968 | 96.65 |
| 9.5 | 320,661,302 | 2,798,183 | 0.0087 | 0.9913 | 96.34 |
| 10.5 | 296,811,557 | 10,687,044 | 0.0360 | 0.9640 | 95.50 |
| 11.5 | 272,085,060 | 1,115,073 | 0.0041 | 0.9959 | 92.06 |
| 12.5 | 261,205,188 | 2,183,422 | 0.0084 | 0.9916 | 91.68 |
| 13.5 | 256,653,691 | 4,733,706 | 0.0184 | 0.9816 | 90.92 |
| 14.5 | 251,634,198 | 2,028,131 | 0.0081 | 0.9919 | 89.24 |
| 15.5 | 244,928,934 | 647,883 | 0.0026 | 0.9974 | 88.52 |
| 16.5 | 240,820,755 | 531,231 | 0.0022 | 0.9978 | 88.29 |
| 17.5 | 237,393,043 | 1,824,892 | 0.0077 | 0.9923 | 88.09 |
| 18.5 | 225,184,375 | 586,589 | 0.0026 | 0.9974 | 87.42 |
| 19.5 | 222,573,363 | 3,065,231 | 0.0138 | 0.9862 | 87.19 |
| 20.5 | 218,824,349 | 3,470,449 | 0.0159 | 0.9841 | 85.99 |
| 21.5 | 208,974,789 | 1,251,775 | 0.0060 | 0.9940 | 84.62 |
| 22.5 | 200,466,351 | 1,180,811 | 0.0059 | 0.9941 | 84.12 |
| 23.5 | 189,738,489 | 1,759,303 | 0.0093 | 0.9907 | 83.62 |
| 24.5 | 173,039,435 | 2,762,890 | 0.0160 | 0.9840 | 82.85 |
| 25.5 | 168,767,072 | 2,760,816 | 0.0164 | 0.9836 | 81.52 |
| 26.5 | 164,721,313 | 707,261 | 0.0043 | 0.9957 | 80.19 |
| 27.5 | 179,148,106 | 383,177 | 0.0021 | 0.9979 | 79.85 |
| 28.5 | 172,455,707 | 527,929 | 0.0031 | 0.9969 | 79.67 |
| 29.5 | 169,272,115 | 179,233 | 0.0011 | 0.9989 | 79.43 |
| 30.5 | 152,707,004 | 210,477 | 0.0014 | 0.9986 | 79.35 |
| 31.5 | 53,516,802 | 265,877 | 0.0050 | 0.9950 | 79.24 |
| 32.5 | 37,634,755 | 401,217 | 0.0107 | 0.9893 | 78.84 |
| 33.5 | 21,579,017 | 97,199 | 0.0045 | 0.9955 | 78.00 |
| 34.5 | 12,728,894 | 107,278 | 0.0084 | 0.9916 | 77.65 |
| 35.5 | 11,306,331 | 98,188 | 0.0087 | 0.9913 | 77.00 |
| 36.5 | 10,480,875 | 31,634 | 0.0030 | 0.9970 | 76.33 |
| 37.5 | 9,936,141 | 29,372 | 0.0030 | 0.9970 | 76.10 |
| 38.5 | 9,451,728 | 68,309 | 0.0072 | 0.9928 | 75.87 |

DUKE ENERGY PROGRESS

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 9,393,506 | 49,901 | 0.0053 | 0.9947 | 75.32 |
| 40.5 | 8,886,942 | 1,453,729 | 0.1636 | 0.8364 | 74.92 |
| 41.5 | 4,823,665 | 13 | 0.0000 | 1.0000 | 62.67 |
| 42.5 | 4,688,989 | 52,440 | 0.0112 | 0.9888 | 62.67 |
| 43.5 | 1,896,426 | 1,449 | 0.0008 | 0.9992 | 61.97 |
| 44.5 | 1,874,529 | 48,835 | 0.0261 | 0.9739 | 61.92 |
| 45.5 | 1,825,694 | 726,199 | 0.3978 | 0.6022 | 60.31 |
| 46.5 | 1,025,597 | 2,363 | 0.0023 | 0.9977 | 36.32 |
| 47.5 | 97 | | 0.0000 | 1.0000 | 36.24 |
| 48.5 | 111 | | 0.0000 | 1.0000 | 36.24 |
| 49.5 | 111 | | 0.0000 | 1.0000 | 36.24 |
| 50.5 | 111 | | 0.0000 | 1.0000 | 36.24 |
| 51.5 | 111 | | 0.0000 | 1.0000 | 36.24 |
| 52.5 | 111 | 49 | 0.4427 | 0.5573 | 36.24 |
| 53.5 | 78,054 | | 0.0000 | 1.0000 | 20.19 |
| 54.5 | 78,054 | | 0.0000 | 1.0000 | 20.19 |
| 55.5 | 78,054 | | 0.0000 | 1.0000 | 20.19 |
| 56.5 | 78,054 | 48 | 0.0006 | 0.9994 | 20.19 |
| 57.5 | 78,006 | 205 | 0.0026 | 0.9974 | 20.18 |
| 58.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 59.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 60.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 61.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 62.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 63.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 64.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 65.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 66.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 67.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 68.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 69.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 70.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 71.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 72.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 73.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 74.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 75.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 76.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 77.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 78.5 | 14 | | 0.0000 | 1.0000 | 20.13 |

DUKE ENERGY PROGRESS

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1971-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 14 | | 0.0000 | 1.0000 | 20.13 |
| 80.5 | 14 | 14 | 1.0000 | | 20.13 |
| 81.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 441,276,658 | 11,439 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 395,783,085 | 76,981 | 0.0002 | 0.9998 | 100.00 |
| 1.5 | 334,566,823 | 279,848 | 0.0008 | 0.9992 | 99.98 |
| 2.5 | 307,421,136 | 465,990 | 0.0015 | 0.9985 | 99.89 |
| 3.5 | 260,417,410 | 318,327 | 0.0012 | 0.9988 | 99.74 |
| 4.5 | 263,685,246 | 1,631,346 | 0.0062 | 0.9938 | 99.62 |
| 5.5 | 233,950,575 | 1,746,458 | 0.0075 | 0.9925 | 99.00 |
| 6.5 | 171,197,135 | 2,772,495 | 0.0162 | 0.9838 | 98.27 |
| 7.5 | 149,537,368 | 462,540 | 0.0031 | 0.9969 | 96.67 |
| 8.5 | 150,819,275 | 284,484 | 0.0019 | 0.9981 | 96.38 |
| 9.5 | 149,948,286 | 378,575 | 0.0025 | 0.9975 | 96.19 |
| 10.5 | 144,296,747 | 1,622,284 | 0.0112 | 0.9888 | 95.95 |
| 11.5 | 214,086,656 | 673,977 | 0.0031 | 0.9969 | 94.87 |
| 12.5 | 217,161,959 | 1,904,532 | 0.0088 | 0.9912 | 94.57 |
| 13.5 | 225,716,485 | 876,375 | 0.0039 | 0.9961 | 93.74 |
| 14.5 | 232,906,663 | 1,644,065 | 0.0071 | 0.9929 | 93.38 |
| 15.5 | 228,849,122 | 382,244 | 0.0017 | 0.9983 | 92.72 |
| 16.5 | 227,198,984 | 357,256 | 0.0016 | 0.9984 | 92.57 |
| 17.5 | 225,725,513 | 1,381,254 | 0.0061 | 0.9939 | 92.42 |
| 18.5 | 215,055,679 | 545,177 | 0.0025 | 0.9975 | 91.85 |
| 19.5 | 213,479,823 | 3,050,856 | 0.0143 | 0.9857 | 91.62 |
| 20.5 | 210,269,848 | 2,939,792 | 0.0140 | 0.9860 | 90.31 |
| 21.5 | 204,034,395 | 1,250,769 | 0.0061 | 0.9939 | 89.05 |
| 22.5 | 195,681,885 | 1,153,531 | 0.0059 | 0.9941 | 88.50 |
| 23.5 | 187,794,493 | 1,759,303 | 0.0094 | 0.9906 | 87.98 |
| 24.5 | 171,060,071 | 2,762,738 | 0.0162 | 0.9838 | 87.16 |
| 25.5 | 166,788,471 | 2,676,588 | 0.0160 | 0.9840 | 85.75 |
| 26.5 | 162,926,526 | 703,636 | 0.0043 | 0.9957 | 84.37 |
| 27.5 | 179,145,463 | 383,177 | 0.0021 | 0.9979 | 84.01 |
| 28.5 | 172,453,064 | 527,763 | 0.0031 | 0.9969 | 83.83 |
| 29.5 | 169,271,857 | 179,233 | 0.0011 | 0.9989 | 83.57 |
| 30.5 | 152,706,763 | 210,477 | 0.0014 | 0.9986 | 83.48 |
| 31.5 | 53,516,561 | 265,877 | 0.0050 | 0.9950 | 83.37 |
| 32.5 | 37,634,514 | 401,217 | 0.0107 | 0.9893 | 82.96 |
| 33.5 | 21,578,777 | 97,199 | 0.0045 | 0.9955 | 82.07 |
| 34.5 | 12,728,653 | 107,278 | 0.0084 | 0.9916 | 81.70 |
| 35.5 | 11,306,091 | 98,188 | 0.0087 | 0.9913 | 81.01 |
| 36.5 | 10,480,634 | 31,634 | 0.0030 | 0.9970 | 80.31 |
| 37.5 | 9,935,900 | 29,372 | 0.0030 | 0.9970 | 80.07 |
| 38.5 | 9,451,487 | 68,231 | 0.0072 | 0.9928 | 79.83 |

DUKE ENERGY PROGRESS

ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 9,393,343 | 49,901 | 0.0053 | 0.9947 | 79.25 |
| 40.5 | 8,886,779 | 1,453,729 | 0.1636 | 0.8364 | 78.83 |
| 41.5 | 4,823,503 | 13 | 0.0000 | 1.0000 | 65.94 |
| 42.5 | 4,688,827 | 52,374 | 0.0112 | 0.9888 | 65.94 |
| 43.5 | 1,896,329 | 1,449 | 0.0008 | 0.9992 | 65.20 |
| 44.5 | 1,874,432 | 48,835 | 0.0261 | 0.9739 | 65.15 |
| 45.5 | 1,825,597 | 726,199 | 0.3978 | 0.6022 | 63.45 |
| 46.5 | 1,025,500 | 2,363 | 0.0023 | 0.9977 | 38.21 |
| 47.5 | | | | | 38.12 |
| 48.5 | 49 | | 0.0000 | | |
| 49.5 | 49 | | 0.0000 | | |
| 50.5 | 49 | | 0.0000 | | |
| 51.5 | 49 | | 0.0000 | | |
| 52.5 | 97 | 49 | 0.5053 | | |
| 53.5 | 78,040 | | 0.0000 | | |
| 54.5 | 78,040 | | 0.0000 | | |
| 55.5 | 78,040 | | 0.0000 | | |
| 56.5 | 78,040 | 48 | 0.0006 | | |
| 57.5 | 77,992 | 205 | 0.0026 | | |
| 58.5 | | | | | |
| 59.5 | | | | | |
| 60.5 | | | | | |
| 61.5 | | | | | |
| 62.5 | | | | | |
| 63.5 | | | | | |
| 64.5 | | | | | |
| 65.5 | | | | | |
| 66.5 | | | | | |
| 67.5 | | | | | |
| 68.5 | | | | | |
| 69.5 | | | | | |
| 70.5 | | | | | |
| 71.5 | | | | | |
| 72.5 | | | | | |
| 73.5 | | | | | |
| 74.5 | | | | | |
| 75.5 | | | | | |
| 76.5 | 14 | | 0.0000 | | |
| 77.5 | 14 | | 0.0000 | | |
| 78.5 | 14 | | 0.0000 | | |

DUKE ENERGY PROGRESS

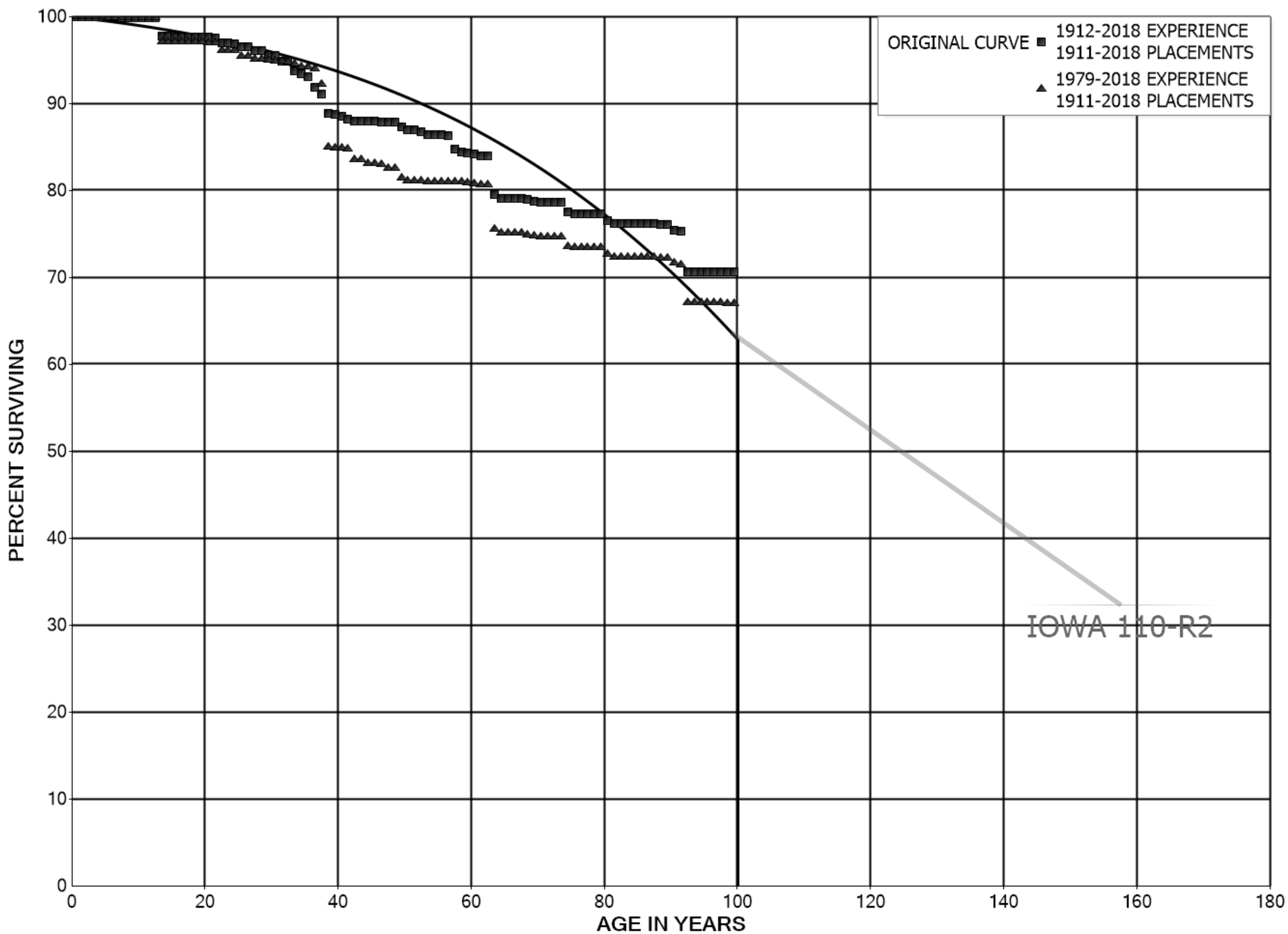
ACCOUNT 325 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2018 EXPERIENCE BAND 1999-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 14 | | 0.0000 | | |
| 80.5 | 14 | 14 | 1.0000 | | |
| 81.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 331 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 19,142,626 | 1,780 | 0.0001 | 0.9999 | 100.00 |
| 0.5 | 14,977,680 | 2,066 | 0.0001 | 0.9999 | 99.99 |
| 1.5 | 12,288,215 | 6,743 | 0.0005 | 0.9995 | 99.98 |
| 2.5 | 12,006,213 | 12 | 0.0000 | 1.0000 | 99.92 |
| 3.5 | 11,994,009 | 103 | 0.0000 | 1.0000 | 99.92 |
| 4.5 | 11,840,824 | 3,225 | 0.0003 | 0.9997 | 99.92 |
| 5.5 | 11,372,245 | 21 | 0.0000 | 1.0000 | 99.89 |
| 6.5 | 11,325,178 | 475 | 0.0000 | 1.0000 | 99.89 |
| 7.5 | 11,652,866 | 262 | 0.0000 | 1.0000 | 99.89 |
| 8.5 | 11,582,372 | 9 | 0.0000 | 1.0000 | 99.89 |
| 9.5 | 11,555,415 | 8,381 | 0.0007 | 0.9993 | 99.89 |
| 10.5 | 10,963,735 | 498 | 0.0000 | 1.0000 | 99.81 |
| 11.5 | 10,970,480 | 70 | 0.0000 | 1.0000 | 99.81 |
| 12.5 | 10,970,410 | 233,507 | 0.0213 | 0.9787 | 99.81 |
| 13.5 | 10,579,125 | 844 | 0.0001 | 0.9999 | 97.69 |
| 14.5 | 10,589,307 | 1,880 | 0.0002 | 0.9998 | 97.68 |
| 15.5 | 10,465,174 | 386 | 0.0000 | 1.0000 | 97.66 |
| 16.5 | 10,456,129 | 1,995 | 0.0002 | 0.9998 | 97.66 |
| 17.5 | 10,121,992 | 823 | 0.0001 | 0.9999 | 97.64 |
| 18.5 | 9,937,414 | 1,518 | 0.0002 | 0.9998 | 97.63 |
| 19.5 | 8,522,938 | 4,625 | 0.0005 | 0.9995 | 97.61 |
| 20.5 | 7,795,795 | 357 | 0.0000 | 1.0000 | 97.56 |
| 21.5 | 6,981,520 | 44,448 | 0.0064 | 0.9936 | 97.56 |
| 22.5 | 5,093,594 | 2,312 | 0.0005 | 0.9995 | 96.94 |
| 23.5 | 5,063,423 | 189 | 0.0000 | 1.0000 | 96.89 |
| 24.5 | 4,661,897 | 16,866 | 0.0036 | 0.9964 | 96.89 |
| 25.5 | 4,639,011 | 2,484 | 0.0005 | 0.9995 | 96.54 |
| 26.5 | 4,562,879 | 17,594 | 0.0039 | 0.9961 | 96.49 |
| 27.5 | 4,543,413 | 632 | 0.0001 | 0.9999 | 96.11 |
| 28.5 | 4,388,901 | 24,986 | 0.0057 | 0.9943 | 96.10 |
| 29.5 | 4,363,916 | 2,571 | 0.0006 | 0.9994 | 95.55 |
| 30.5 | 4,361,345 | 30,461 | 0.0070 | 0.9930 | 95.50 |
| 31.5 | 4,219,279 | 2,054 | 0.0005 | 0.9995 | 94.83 |
| 32.5 | 4,167,386 | 44,590 | 0.0107 | 0.9893 | 94.78 |
| 33.5 | 2,821,229 | 11,799 | 0.0042 | 0.9958 | 93.77 |
| 34.5 | 2,807,583 | 9,237 | 0.0033 | 0.9967 | 93.38 |
| 35.5 | 2,604,525 | 34,751 | 0.0133 | 0.9867 | 93.07 |
| 36.5 | 2,556,060 | 21,735 | 0.0085 | 0.9915 | 91.83 |
| 37.5 | 2,531,518 | 61,963 | 0.0245 | 0.9755 | 91.05 |
| 38.5 | 2,458,647 | 3,760 | 0.0015 | 0.9985 | 88.82 |

DUKE ENERGY PROGRESS

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 2,419,181 | 4,929 | 0.0020 | 0.9980 | 88.68 |
| 40.5 | 2,332,376 | 8,251 | 0.0035 | 0.9965 | 88.50 |
| 41.5 | 2,186,832 | 5,265 | 0.0024 | 0.9976 | 88.19 |
| 42.5 | 2,181,411 | 0 | 0.0000 | 1.0000 | 87.98 |
| 43.5 | 2,171,777 | 1,866 | 0.0009 | 0.9991 | 87.98 |
| 44.5 | 2,110,307 | 15 | 0.0000 | 1.0000 | 87.90 |
| 45.5 | 2,086,621 | 601 | 0.0003 | 0.9997 | 87.90 |
| 46.5 | 2,058,123 | 1,231 | 0.0006 | 0.9994 | 87.88 |
| 47.5 | 2,055,871 | 9 | 0.0000 | 1.0000 | 87.82 |
| 48.5 | 2,044,773 | 12,552 | 0.0061 | 0.9939 | 87.82 |
| 49.5 | 2,032,056 | 6,545 | 0.0032 | 0.9968 | 87.28 |
| 50.5 | 2,022,354 | 1,319 | 0.0007 | 0.9993 | 87.00 |
| 51.5 | 2,020,677 | 5,552 | 0.0027 | 0.9973 | 86.95 |
| 52.5 | 2,014,085 | 6,140 | 0.0030 | 0.9970 | 86.71 |
| 53.5 | 2,005,527 | 0 | 0.0000 | 1.0000 | 86.44 |
| 54.5 | 2,005,527 | 462 | 0.0002 | 0.9998 | 86.44 |
| 55.5 | 2,004,900 | 4,392 | 0.0022 | 0.9978 | 86.42 |
| 56.5 | 1,999,671 | 35,890 | 0.0179 | 0.9821 | 86.23 |
| 57.5 | 1,963,050 | 7,153 | 0.0036 | 0.9964 | 84.69 |
| 58.5 | 1,805,074 | 1,728 | 0.0010 | 0.9990 | 84.38 |
| 59.5 | 1,802,621 | 3,459 | 0.0019 | 0.9981 | 84.30 |
| 60.5 | 1,791,356 | 3,179 | 0.0018 | 0.9982 | 84.14 |
| 61.5 | 1,786,600 | 901 | 0.0005 | 0.9995 | 83.99 |
| 62.5 | 1,784,111 | 94,681 | 0.0531 | 0.9469 | 83.94 |
| 63.5 | 1,686,663 | 8,638 | 0.0051 | 0.9949 | 79.49 |
| 64.5 | 1,678,025 | 6 | 0.0000 | 1.0000 | 79.08 |
| 65.5 | 1,670,204 | 3 | 0.0000 | 1.0000 | 79.08 |
| 66.5 | 1,669,705 | 13 | 0.0000 | 1.0000 | 79.08 |
| 67.5 | 1,666,956 | 3,290 | 0.0020 | 0.9980 | 79.08 |
| 68.5 | 1,652,415 | 3,689 | 0.0022 | 0.9978 | 78.92 |
| 69.5 | 1,648,726 | 2,000 | 0.0012 | 0.9988 | 78.75 |
| 70.5 | 1,643,905 | | 0.0000 | 1.0000 | 78.65 |
| 71.5 | 1,643,905 | 101 | 0.0001 | 0.9999 | 78.65 |
| 72.5 | 1,642,541 | | 0.0000 | 1.0000 | 78.65 |
| 73.5 | 1,642,541 | 24,245 | 0.0148 | 0.9852 | 78.65 |
| 74.5 | 1,618,296 | 3,568 | 0.0022 | 0.9978 | 77.49 |
| 75.5 | 1,614,506 | 15 | 0.0000 | 1.0000 | 77.32 |
| 76.5 | 1,612,121 | | 0.0000 | 1.0000 | 77.32 |
| 77.5 | 1,612,121 | | 0.0000 | 1.0000 | 77.32 |
| 78.5 | 1,612,121 | | 0.0000 | 1.0000 | 77.32 |

DUKE ENERGY PROGRESS

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 1,612,121 | 16,459 | 0.0102 | 0.9898 | 77.32 |
| 80.5 | 1,595,662 | 7,727 | 0.0048 | 0.9952 | 76.53 |
| 81.5 | 1,587,935 | 272 | 0.0002 | 0.9998 | 76.16 |
| 82.5 | 1,587,662 | | 0.0000 | 1.0000 | 76.14 |
| 83.5 | 1,587,662 | | 0.0000 | 1.0000 | 76.14 |
| 84.5 | 1,587,662 | | 0.0000 | 1.0000 | 76.14 |
| 85.5 | 1,587,662 | | 0.0000 | 1.0000 | 76.14 |
| 86.5 | 1,587,662 | | 0.0000 | 1.0000 | 76.14 |
| 87.5 | 1,587,662 | 1,203 | 0.0008 | 0.9992 | 76.14 |
| 88.5 | 966,665 | | 0.0000 | 1.0000 | 76.08 |
| 89.5 | 966,651 | 8,246 | 0.0085 | 0.9915 | 76.08 |
| 90.5 | 295,917 | 741 | 0.0025 | 0.9975 | 75.44 |
| 91.5 | 295,176 | 18,040 | 0.0611 | 0.9389 | 75.25 |
| 92.5 | 277,136 | | 0.0000 | 1.0000 | 70.65 |
| 93.5 | 277,136 | | 0.0000 | 1.0000 | 70.65 |
| 94.5 | 277,136 | | 0.0000 | 1.0000 | 70.65 |
| 95.5 | 277,136 | | 0.0000 | 1.0000 | 70.65 |
| 96.5 | 277,136 | | 0.0000 | 1.0000 | 70.65 |
| 97.5 | 276,282 | 147 | 0.0005 | 0.9995 | 70.65 |
| 98.5 | 276,135 | | 0.0000 | 1.0000 | 70.61 |
| 99.5 | 276,135 | | 0.0000 | 1.0000 | 70.61 |
| 100.5 | 276,135 | | 0.0000 | 1.0000 | 70.61 |
| 101.5 | 252,136 | | 0.0000 | 1.0000 | 70.61 |
| 102.5 | 252,136 | | 0.0000 | 1.0000 | 70.61 |
| 103.5 | 251,783 | | 0.0000 | 1.0000 | 70.61 |
| 104.5 | 251,783 | | 0.0000 | 1.0000 | 70.61 |
| 105.5 | 250,387 | | 0.0000 | 1.0000 | 70.61 |
| 106.5 | 6,298 | | 0.0000 | 1.0000 | 70.61 |
| 107.5 | | | | | 70.61 |

DUKE ENERGY PROGRESS

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 16,496,359 | 1,780 | 0.0001 | 0.9999 | 100.00 |
| 0.5 | 12,399,441 | 2,066 | 0.0002 | 0.9998 | 99.99 |
| 1.5 | 9,847,283 | 6,743 | 0.0007 | 0.9993 | 99.97 |
| 2.5 | 9,565,621 | 12 | 0.0000 | 1.0000 | 99.90 |
| 3.5 | 9,563,350 | 29 | 0.0000 | 1.0000 | 99.90 |
| 4.5 | 9,480,518 | 2,591 | 0.0003 | 0.9997 | 99.90 |
| 5.5 | 9,029,016 | 9 | 0.0000 | 1.0000 | 99.88 |
| 6.5 | 9,009,912 | 9 | 0.0000 | 1.0000 | 99.88 |
| 7.5 | 9,339,094 | 35 | 0.0000 | 1.0000 | 99.88 |
| 8.5 | 9,268,899 | 9 | 0.0000 | 1.0000 | 99.88 |
| 9.5 | 9,242,361 | 8,381 | 0.0009 | 0.9991 | 99.88 |
| 10.5 | 8,653,968 | | 0.0000 | 1.0000 | 99.79 |
| 11.5 | 8,661,569 | 70 | 0.0000 | 1.0000 | 99.79 |
| 12.5 | 8,663,436 | 233,507 | 0.0270 | 0.9730 | 99.78 |
| 13.5 | 8,277,457 | | 0.0000 | 1.0000 | 97.09 |
| 14.5 | 8,295,534 | 1,880 | 0.0002 | 0.9998 | 97.09 |
| 15.5 | 8,171,565 | 13 | 0.0000 | 1.0000 | 97.07 |
| 16.5 | 8,168,997 | 1,995 | 0.0002 | 0.9998 | 97.07 |
| 17.5 | 7,837,256 | 35 | 0.0000 | 1.0000 | 97.05 |
| 18.5 | 7,808,569 | 1,518 | 0.0002 | 0.9998 | 97.05 |
| 19.5 | 6,450,878 | 3,335 | 0.0005 | 0.9995 | 97.03 |
| 20.5 | 5,732,864 | 357 | 0.0001 | 0.9999 | 96.98 |
| 21.5 | 4,920,167 | 44,448 | 0.0090 | 0.9910 | 96.97 |
| 22.5 | 3,033,830 | 2,312 | 0.0008 | 0.9992 | 96.10 |
| 23.5 | 3,006,428 | 189 | 0.0001 | 0.9999 | 96.02 |
| 24.5 | 2,608,762 | 16,419 | 0.0063 | 0.9937 | 96.02 |
| 25.5 | 2,594,145 | 847 | 0.0003 | 0.9997 | 95.41 |
| 26.5 | 2,520,225 | 9,513 | 0.0038 | 0.9962 | 95.38 |
| 27.5 | 2,511,590 | 254 | 0.0001 | 0.9999 | 95.02 |
| 28.5 | 2,369,455 | 1,105 | 0.0005 | 0.9995 | 95.01 |
| 29.5 | 2,368,350 | 2,571 | 0.0011 | 0.9989 | 94.97 |
| 30.5 | 2,368,600 | 793 | 0.0003 | 0.9997 | 94.87 |
| 31.5 | 2,259,378 | 1,654 | 0.0007 | 0.9993 | 94.83 |
| 32.5 | 2,209,155 | 7,051 | 0.0032 | 0.9968 | 94.76 |
| 33.5 | 900,537 | 2,959 | 0.0033 | 0.9967 | 94.46 |
| 34.5 | 895,840 | 138 | 0.0002 | 0.9998 | 94.15 |
| 35.5 | 705,208 | 1,674 | 0.0024 | 0.9976 | 94.14 |
| 36.5 | 698,735 | 12,651 | 0.0181 | 0.9819 | 93.91 |
| 37.5 | 686,178 | 54,464 | 0.0794 | 0.9206 | 92.21 |
| 38.5 | 620,899 | 30 | 0.0000 | 1.0000 | 84.89 |

DUKE ENERGY PROGRESS

ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 585,163 | 208 | 0.0004 | 0.9996 | 84.89 |
| 40.5 | 504,057 | 995 | 0.0020 | 0.9980 | 84.86 |
| 41.5 | 365,768 | 5,265 | 0.0144 | 0.9856 | 84.69 |
| 42.5 | 360,347 | 0 | 0.0000 | 1.0000 | 83.47 |
| 43.5 | 350,714 | 1,866 | 0.0053 | 0.9947 | 83.47 |
| 44.5 | 289,244 | 15 | 0.0001 | 0.9999 | 83.03 |
| 45.5 | 265,558 | 337 | 0.0013 | 0.9987 | 83.02 |
| 46.5 | 237,323 | 1,231 | 0.0052 | 0.9948 | 82.92 |
| 47.5 | 235,071 | 9 | 0.0000 | 1.0000 | 82.49 |
| 48.5 | 991,281 | 12,552 | 0.0127 | 0.9873 | 82.49 |
| 49.5 | 978,579 | 4,117 | 0.0042 | 0.9958 | 81.44 |
| 50.5 | 1,650,373 | 77 | 0.0000 | 1.0000 | 81.10 |
| 51.5 | 1,649,938 | 378 | 0.0002 | 0.9998 | 81.10 |
| 52.5 | 1,648,521 | 2,904 | 0.0018 | 0.9982 | 81.08 |
| 53.5 | 1,643,198 | 0 | 0.0000 | 1.0000 | 80.93 |
| 54.5 | 1,643,198 | | 0.0000 | 1.0000 | 80.93 |
| 55.5 | 1,643,033 | 1 | 0.0000 | 1.0000 | 80.93 |
| 56.5 | 1,642,195 | 1 | 0.0000 | 1.0000 | 80.93 |
| 57.5 | 1,642,317 | 766 | 0.0005 | 0.9995 | 80.93 |
| 58.5 | 1,490,728 | 111 | 0.0001 | 0.9999 | 80.90 |
| 59.5 | 1,489,892 | 2,362 | 0.0016 | 0.9984 | 80.89 |
| 60.5 | 1,479,724 | 3,179 | 0.0021 | 0.9979 | 80.76 |
| 61.5 | 1,498,967 | 1 | 0.0000 | 1.0000 | 80.59 |
| 62.5 | 1,497,378 | 94,681 | 0.0632 | 0.9368 | 80.59 |
| 63.5 | 1,400,283 | 8,638 | 0.0062 | 0.9938 | 75.49 |
| 64.5 | 1,391,792 | 6 | 0.0000 | 1.0000 | 75.03 |
| 65.5 | 1,385,367 | 3 | 0.0000 | 1.0000 | 75.03 |
| 66.5 | 1,655,651 | 13 | 0.0000 | 1.0000 | 75.03 |
| 67.5 | 1,666,956 | 3,290 | 0.0020 | 0.9980 | 75.03 |
| 68.5 | 1,652,415 | 3,689 | 0.0022 | 0.9978 | 74.88 |
| 69.5 | 1,648,726 | 2,000 | 0.0012 | 0.9988 | 74.71 |
| 70.5 | 1,643,905 | | 0.0000 | 1.0000 | 74.62 |
| 71.5 | 1,643,905 | 101 | 0.0001 | 0.9999 | 74.62 |
| 72.5 | 1,642,541 | | 0.0000 | 1.0000 | 74.62 |
| 73.5 | 1,642,541 | 24,245 | 0.0148 | 0.9852 | 74.62 |
| 74.5 | 1,618,296 | 3,568 | 0.0022 | 0.9978 | 73.51 |
| 75.5 | 1,614,506 | 15 | 0.0000 | 1.0000 | 73.35 |
| 76.5 | 1,612,121 | | 0.0000 | 1.0000 | 73.35 |
| 77.5 | 1,612,121 | | 0.0000 | 1.0000 | 73.35 |
| 78.5 | 1,612,121 | | 0.0000 | 1.0000 | 73.35 |

DUKE ENERGY PROGRESS

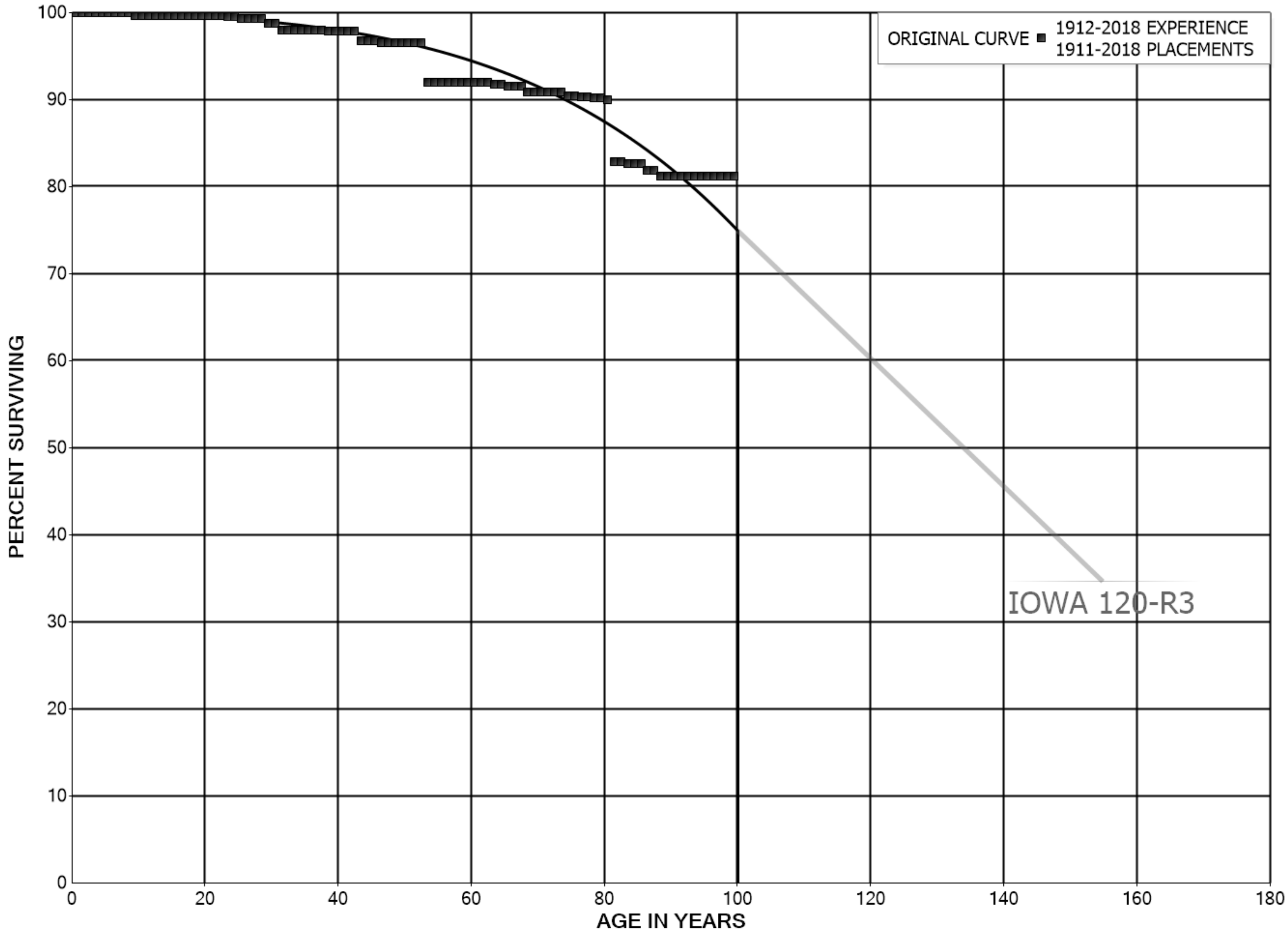
ACCOUNT 331 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 1,612,121 | 16,459 | 0.0102 | 0.9898 | 73.35 |
| 80.5 | 1,595,662 | 7,727 | 0.0048 | 0.9952 | 72.60 |
| 81.5 | 1,587,935 | 272 | 0.0002 | 0.9998 | 72.25 |
| 82.5 | 1,587,662 | | 0.0000 | 1.0000 | 72.24 |
| 83.5 | 1,587,662 | | 0.0000 | 1.0000 | 72.24 |
| 84.5 | 1,587,662 | | 0.0000 | 1.0000 | 72.24 |
| 85.5 | 1,587,662 | | 0.0000 | 1.0000 | 72.24 |
| 86.5 | 1,587,662 | | 0.0000 | 1.0000 | 72.24 |
| 87.5 | 1,587,662 | 1,203 | 0.0008 | 0.9992 | 72.24 |
| 88.5 | 966,665 | | 0.0000 | 1.0000 | 72.18 |
| 89.5 | 966,651 | 8,246 | 0.0085 | 0.9915 | 72.18 |
| 90.5 | 295,917 | 741 | 0.0025 | 0.9975 | 71.57 |
| 91.5 | 295,176 | 18,040 | 0.0611 | 0.9389 | 71.39 |
| 92.5 | 277,136 | | 0.0000 | 1.0000 | 67.03 |
| 93.5 | 277,136 | | 0.0000 | 1.0000 | 67.03 |
| 94.5 | 277,136 | | 0.0000 | 1.0000 | 67.03 |
| 95.5 | 277,136 | | 0.0000 | 1.0000 | 67.03 |
| 96.5 | 277,136 | | 0.0000 | 1.0000 | 67.03 |
| 97.5 | 276,282 | 147 | 0.0005 | 0.9995 | 67.03 |
| 98.5 | 276,135 | | 0.0000 | 1.0000 | 66.99 |
| 99.5 | 276,135 | | 0.0000 | 1.0000 | 66.99 |
| 100.5 | 276,135 | | 0.0000 | 1.0000 | 66.99 |
| 101.5 | 252,136 | | 0.0000 | 1.0000 | 66.99 |
| 102.5 | 252,136 | | 0.0000 | 1.0000 | 66.99 |
| 103.5 | 251,783 | | 0.0000 | 1.0000 | 66.99 |
| 104.5 | 251,783 | | 0.0000 | 1.0000 | 66.99 |
| 105.5 | 250,387 | | 0.0000 | 1.0000 | 66.99 |
| 106.5 | 6,298 | | 0.0000 | 1.0000 | 66.99 |
| 107.5 | | | | | 66.99 |

DUKE ENERGY PROGRESS
ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS
ORIGINAL AND SMOOTH SURVIVOR CURVES




Gannett Fleming

DUKE ENERGY PROGRESS

ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 60,534,090 | 2,253 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 57,016,858 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 55,661,740 | 39 | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 53,955,523 | 62 | 0.0000 | 1.0000 | 100.00 |
| 3.5 | 53,260,875 | | 0.0000 | 1.0000 | 100.00 |
| 4.5 | 53,262,300 | 7 | 0.0000 | 1.0000 | 100.00 |
| 5.5 | 51,799,968 | | 0.0000 | 1.0000 | 100.00 |
| 6.5 | 51,670,034 | 6,888 | 0.0001 | 0.9999 | 100.00 |
| 7.5 | 47,717,019 | 3,584 | 0.0001 | 0.9999 | 99.98 |
| 8.5 | 47,024,000 | 162,457 | 0.0035 | 0.9965 | 99.98 |
| 9.5 | 46,861,543 | 23,042 | 0.0005 | 0.9995 | 99.63 |
| 10.5 | 46,674,717 | | 0.0000 | 1.0000 | 99.58 |
| 11.5 | 46,674,717 | 216 | 0.0000 | 1.0000 | 99.58 |
| 12.5 | 46,674,501 | | 0.0000 | 1.0000 | 99.58 |
| 13.5 | 46,571,937 | | 0.0000 | 1.0000 | 99.58 |
| 14.5 | 46,569,845 | | 0.0000 | 1.0000 | 99.58 |
| 15.5 | 46,569,836 | | 0.0000 | 1.0000 | 99.58 |
| 16.5 | 39,212,724 | | 0.0000 | 1.0000 | 99.58 |
| 17.5 | 31,571,697 | 337 | 0.0000 | 1.0000 | 99.58 |
| 18.5 | 31,525,658 | | 0.0000 | 1.0000 | 99.58 |
| 19.5 | 30,955,114 | | 0.0000 | 1.0000 | 99.58 |
| 20.5 | 30,359,946 | 24 | 0.0000 | 1.0000 | 99.58 |
| 21.5 | 28,366,320 | 110 | 0.0000 | 1.0000 | 99.58 |
| 22.5 | 28,014,122 | 15,910 | 0.0006 | 0.9994 | 99.58 |
| 23.5 | 25,705,297 | 21 | 0.0000 | 1.0000 | 99.52 |
| 24.5 | 25,463,590 | 50,415 | 0.0020 | 0.9980 | 99.52 |
| 25.5 | 23,915,652 | 5,574 | 0.0002 | 0.9998 | 99.33 |
| 26.5 | 23,555,910 | 7,851 | 0.0003 | 0.9997 | 99.30 |
| 27.5 | 23,532,001 | | 0.0000 | 1.0000 | 99.27 |
| 28.5 | 22,285,757 | 123,442 | 0.0055 | 0.9945 | 99.27 |
| 29.5 | 22,162,315 | | 0.0000 | 1.0000 | 98.72 |
| 30.5 | 22,083,580 | 162,933 | 0.0074 | 0.9926 | 98.72 |
| 31.5 | 21,907,934 | 117 | 0.0000 | 1.0000 | 97.99 |
| 32.5 | 21,777,735 | 6,454 | 0.0003 | 0.9997 | 97.99 |
| 33.5 | 18,700,005 | | 0.0000 | 1.0000 | 97.96 |
| 34.5 | 18,695,554 | 499 | 0.0000 | 1.0000 | 97.96 |
| 35.5 | 18,228,272 | 1,300 | 0.0001 | 0.9999 | 97.96 |
| 36.5 | 17,958,858 | | 0.0000 | 1.0000 | 97.95 |
| 37.5 | 17,958,858 | 18,343 | 0.0010 | 0.9990 | 97.95 |
| 38.5 | 17,940,515 | 1,905 | 0.0001 | 0.9999 | 97.85 |

DUKE ENERGY PROGRESS

ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 17,938,610 | 2,677 | 0.0001 | 0.9999 | 97.84 |
| 40.5 | 17,926,884 | | 0.0000 | 1.0000 | 97.83 |
| 41.5 | 17,616,270 | | 0.0000 | 1.0000 | 97.83 |
| 42.5 | 17,616,270 | 202,342 | 0.0115 | 0.9885 | 97.83 |
| 43.5 | 17,413,343 | | 0.0000 | 1.0000 | 96.70 |
| 44.5 | 17,413,343 | | 0.0000 | 1.0000 | 96.70 |
| 45.5 | 17,413,343 | 41,928 | 0.0024 | 0.9976 | 96.70 |
| 46.5 | 17,332,322 | 806 | 0.0000 | 1.0000 | 96.47 |
| 47.5 | 17,331,516 | | 0.0000 | 1.0000 | 96.47 |
| 48.5 | 17,331,516 | | 0.0000 | 1.0000 | 96.47 |
| 49.5 | 17,331,516 | | 0.0000 | 1.0000 | 96.47 |
| 50.5 | 17,331,066 | | 0.0000 | 1.0000 | 96.47 |
| 51.5 | 17,331,066 | 2,241 | 0.0001 | 0.9999 | 96.47 |
| 52.5 | 17,328,825 | 809,115 | 0.0467 | 0.9533 | 96.45 |
| 53.5 | 16,517,572 | | 0.0000 | 1.0000 | 91.95 |
| 54.5 | 16,517,572 | | 0.0000 | 1.0000 | 91.95 |
| 55.5 | 16,517,572 | | 0.0000 | 1.0000 | 91.95 |
| 56.5 | 16,517,572 | | 0.0000 | 1.0000 | 91.95 |
| 57.5 | 16,515,860 | 2,375 | 0.0001 | 0.9999 | 91.95 |
| 58.5 | 16,340,925 | | 0.0000 | 1.0000 | 91.94 |
| 59.5 | 16,338,605 | | 0.0000 | 1.0000 | 91.94 |
| 60.5 | 16,338,605 | | 0.0000 | 1.0000 | 91.94 |
| 61.5 | 16,338,605 | | 0.0000 | 1.0000 | 91.94 |
| 62.5 | 16,338,605 | 45,119 | 0.0028 | 0.9972 | 91.94 |
| 63.5 | 16,293,486 | | 0.0000 | 1.0000 | 91.68 |
| 64.5 | 16,293,486 | 25,844 | 0.0016 | 0.9984 | 91.68 |
| 65.5 | 16,267,642 | | 0.0000 | 1.0000 | 91.54 |
| 66.5 | 16,267,642 | | 0.0000 | 1.0000 | 91.54 |
| 67.5 | 16,267,642 | 129,145 | 0.0079 | 0.9921 | 91.54 |
| 68.5 | 16,138,497 | | 0.0000 | 1.0000 | 90.81 |
| 69.5 | 16,138,497 | | 0.0000 | 1.0000 | 90.81 |
| 70.5 | 16,138,497 | 1,275 | 0.0001 | 0.9999 | 90.81 |
| 71.5 | 16,137,221 | 1,014 | 0.0001 | 0.9999 | 90.80 |
| 72.5 | 16,136,207 | | 0.0000 | 1.0000 | 90.80 |
| 73.5 | 16,136,207 | 64,021 | 0.0040 | 0.9960 | 90.80 |
| 74.5 | 16,071,846 | | 0.0000 | 1.0000 | 90.44 |
| 75.5 | 16,071,846 | 27,158 | 0.0017 | 0.9983 | 90.44 |
| 76.5 | 16,043,116 | 6,948 | 0.0004 | 0.9996 | 90.28 |
| 77.5 | 16,035,133 | 20,263 | 0.0013 | 0.9987 | 90.25 |
| 78.5 | 16,014,870 | 1,887 | 0.0001 | 0.9999 | 90.13 |

DUKE ENERGY PROGRESS

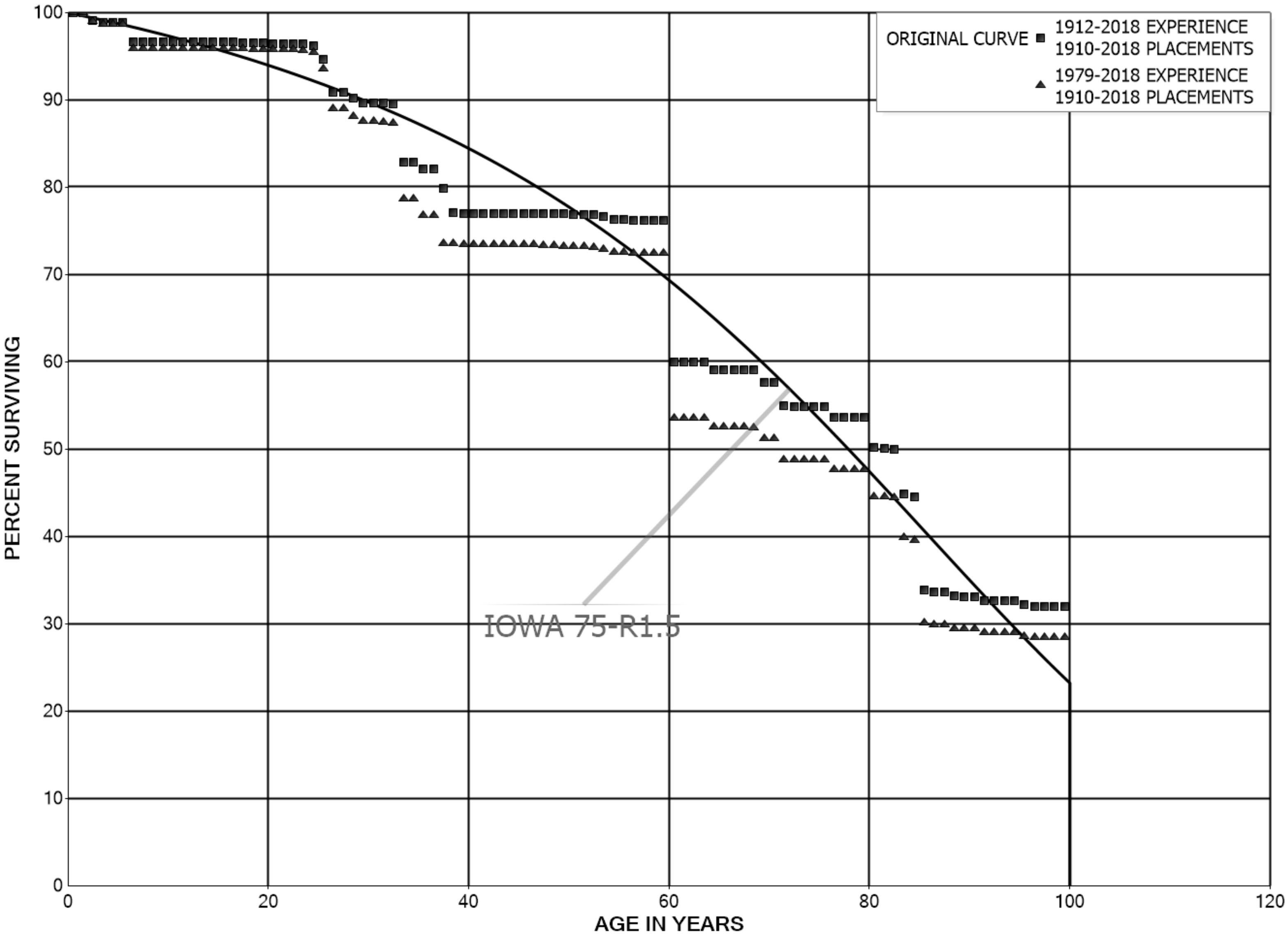
ACCOUNT 332 RESERVOIRS, DAMS AND WATERWAYS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 16,012,983 | 26,458 | 0.0017 | 0.9983 | 90.12 |
| 80.5 | 15,986,525 | 1,276,307 | 0.0798 | 0.9202 | 89.97 |
| 81.5 | 14,710,218 | | 0.0000 | 1.0000 | 82.79 |
| 82.5 | 14,710,218 | 33,840 | 0.0023 | 0.9977 | 82.79 |
| 83.5 | 14,676,378 | | 0.0000 | 1.0000 | 82.60 |
| 84.5 | 14,676,378 | 6,360 | 0.0004 | 0.9996 | 82.60 |
| 85.5 | 14,670,018 | 130,292 | 0.0089 | 0.9911 | 82.56 |
| 86.5 | 14,489,169 | 4,625 | 0.0003 | 0.9997 | 81.83 |
| 87.5 | 14,484,544 | 114,556 | 0.0079 | 0.9921 | 81.80 |
| 88.5 | 5,456,406 | | 0.0000 | 1.0000 | 81.16 |
| 89.5 | 5,456,406 | | 0.0000 | 1.0000 | 81.16 |
| 90.5 | 1,977,178 | 1 | 0.0000 | 1.0000 | 81.16 |
| 91.5 | 1,977,177 | 340 | 0.0002 | 0.9998 | 81.16 |
| 92.5 | 1,976,837 | | 0.0000 | 1.0000 | 81.14 |
| 93.5 | 1,976,837 | | 0.0000 | 1.0000 | 81.14 |
| 94.5 | 1,966,361 | | 0.0000 | 1.0000 | 81.14 |
| 95.5 | 1,957,111 | | 0.0000 | 1.0000 | 81.14 |
| 96.5 | 1,957,111 | | 0.0000 | 1.0000 | 81.14 |
| 97.5 | 1,957,111 | | 0.0000 | 1.0000 | 81.14 |
| 98.5 | 1,957,111 | | 0.0000 | 1.0000 | 81.14 |
| 99.5 | 1,957,111 | | 0.0000 | 1.0000 | 81.14 |
| 100.5 | 1,957,111 | | 0.0000 | 1.0000 | 81.14 |
| 101.5 | 1,943,661 | | 0.0000 | 1.0000 | 81.14 |
| 102.5 | 1,943,661 | | 0.0000 | 1.0000 | 81.14 |
| 103.5 | 1,943,451 | | 0.0000 | 1.0000 | 81.14 |
| 104.5 | 1,943,451 | | 0.0000 | 1.0000 | 81.14 |
| 105.5 | 1,942,637 | | 0.0000 | 1.0000 | 81.14 |
| 106.5 | 45,055 | 747 | 0.0166 | 0.9834 | 81.14 |
| 107.5 | | | | | 79.80 |

DUKE ENERGY PROGRESS
ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 41,794,666 | 6,919 | 0.0002 | 0.9998 | 100.00 |
| 0.5 | 39,990,500 | | 0.0000 | 1.0000 | 99.98 |
| 1.5 | 33,990,137 | 296,203 | 0.0087 | 0.9913 | 99.98 |
| 2.5 | 33,645,161 | 87,285 | 0.0026 | 0.9974 | 99.11 |
| 3.5 | 33,387,324 | | 0.0000 | 1.0000 | 98.86 |
| 4.5 | 33,397,624 | | 0.0000 | 1.0000 | 98.86 |
| 5.5 | 28,241,019 | 650,642 | 0.0230 | 0.9770 | 98.86 |
| 6.5 | 22,100,011 | | 0.0000 | 1.0000 | 96.58 |
| 7.5 | 18,894,898 | 1,815 | 0.0001 | 0.9999 | 96.58 |
| 8.5 | 18,878,409 | | 0.0000 | 1.0000 | 96.57 |
| 9.5 | 18,878,409 | | 0.0000 | 1.0000 | 96.57 |
| 10.5 | 18,878,409 | | 0.0000 | 1.0000 | 96.57 |
| 11.5 | 18,878,409 | | 0.0000 | 1.0000 | 96.57 |
| 12.5 | 18,827,411 | | 0.0000 | 1.0000 | 96.57 |
| 13.5 | 18,816,916 | | 0.0000 | 1.0000 | 96.57 |
| 14.5 | 18,816,916 | | 0.0000 | 1.0000 | 96.57 |
| 15.5 | 18,816,916 | 326 | 0.0000 | 1.0000 | 96.57 |
| 16.5 | 18,508,911 | 11,966 | 0.0006 | 0.9994 | 96.57 |
| 17.5 | 18,496,945 | 1,081 | 0.0001 | 0.9999 | 96.50 |
| 18.5 | 18,354,914 | | 0.0000 | 1.0000 | 96.50 |
| 19.5 | 18,347,088 | 16,664 | 0.0009 | 0.9991 | 96.50 |
| 20.5 | 18,321,528 | 561 | 0.0000 | 1.0000 | 96.41 |
| 21.5 | 17,975,909 | | 0.0000 | 1.0000 | 96.41 |
| 22.5 | 17,974,472 | 1,042 | 0.0001 | 0.9999 | 96.41 |
| 23.5 | 17,973,430 | 34,376 | 0.0019 | 0.9981 | 96.40 |
| 24.5 | 17,534,582 | 293,084 | 0.0167 | 0.9833 | 96.22 |
| 25.5 | 16,277,097 | 644,822 | 0.0396 | 0.9604 | 94.61 |
| 26.5 | 14,138,848 | 1,051 | 0.0001 | 0.9999 | 90.86 |
| 27.5 | 14,098,480 | 111,864 | 0.0079 | 0.9921 | 90.85 |
| 28.5 | 13,455,416 | 69,957 | 0.0052 | 0.9948 | 90.13 |
| 29.5 | 13,141,095 | 779 | 0.0001 | 0.9999 | 89.67 |
| 30.5 | 13,099,355 | 7,005 | 0.0005 | 0.9995 | 89.66 |
| 31.5 | 11,898,271 | 14,154 | 0.0012 | 0.9988 | 89.61 |
| 32.5 | 11,606,517 | 865,792 | 0.0746 | 0.9254 | 89.51 |
| 33.5 | 4,950,500 | 157 | 0.0000 | 1.0000 | 82.83 |
| 34.5 | 4,154,332 | 37,273 | 0.0090 | 0.9910 | 82.83 |
| 35.5 | 4,117,058 | 2,626 | 0.0006 | 0.9994 | 82.08 |
| 36.5 | 4,100,706 | 109,611 | 0.0267 | 0.9733 | 82.03 |
| 37.5 | 3,912,259 | 138,185 | 0.0353 | 0.9647 | 79.84 |
| 38.5 | 3,732,378 | 438 | 0.0001 | 0.9999 | 77.02 |

DUKE ENERGY PROGRESS

ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 3,715,981 | | 0.0000 | 1.0000 | 77.01 |
| 40.5 | 3,715,981 | | 0.0000 | 1.0000 | 77.01 |
| 41.5 | 3,715,792 | 0 | 0.0000 | 1.0000 | 77.01 |
| 42.5 | 3,715,792 | | 0.0000 | 1.0000 | 77.01 |
| 43.5 | 3,715,792 | 0 | 0.0000 | 1.0000 | 77.01 |
| 44.5 | 3,714,918 | | 0.0000 | 1.0000 | 77.01 |
| 45.5 | 3,714,918 | 643 | 0.0002 | 0.9998 | 77.01 |
| 46.5 | 3,704,394 | 1,456 | 0.0004 | 0.9996 | 77.00 |
| 47.5 | 3,702,938 | 87 | 0.0000 | 1.0000 | 76.97 |
| 48.5 | 3,702,852 | 2,603 | 0.0007 | 0.9993 | 76.96 |
| 49.5 | 3,695,439 | 1,760 | 0.0005 | 0.9995 | 76.91 |
| 50.5 | 3,693,679 | | 0.0000 | 1.0000 | 76.87 |
| 51.5 | 3,680,955 | 1,245 | 0.0003 | 0.9997 | 76.87 |
| 52.5 | 3,679,710 | 12,399 | 0.0034 | 0.9966 | 76.85 |
| 53.5 | 3,667,285 | 14,827 | 0.0040 | 0.9960 | 76.59 |
| 54.5 | 3,640,212 | | 0.0000 | 1.0000 | 76.28 |
| 55.5 | 3,640,212 | 4,462 | 0.0012 | 0.9988 | 76.28 |
| 56.5 | 3,615,036 | | 0.0000 | 1.0000 | 76.18 |
| 57.5 | 3,615,036 | 236 | 0.0001 | 0.9999 | 76.18 |
| 58.5 | 2,694,007 | | 0.0000 | 1.0000 | 76.18 |
| 59.5 | 2,694,007 | 572,720 | 0.2126 | 0.7874 | 76.18 |
| 60.5 | 2,121,287 | | 0.0000 | 1.0000 | 59.98 |
| 61.5 | 2,121,287 | | 0.0000 | 1.0000 | 59.98 |
| 62.5 | 2,121,287 | | 0.0000 | 1.0000 | 59.98 |
| 63.5 | 2,121,287 | 31,991 | 0.0151 | 0.9849 | 59.98 |
| 64.5 | 2,089,296 | 684 | 0.0003 | 0.9997 | 59.08 |
| 65.5 | 2,088,612 | | 0.0000 | 1.0000 | 59.06 |
| 66.5 | 2,088,612 | | 0.0000 | 1.0000 | 59.06 |
| 67.5 | 2,088,612 | 1,140 | 0.0005 | 0.9995 | 59.06 |
| 68.5 | 2,083,079 | 48,341 | 0.0232 | 0.9768 | 59.03 |
| 69.5 | 2,034,737 | 175 | 0.0001 | 0.9999 | 57.66 |
| 70.5 | 2,034,562 | 96,683 | 0.0475 | 0.9525 | 57.65 |
| 71.5 | 1,937,879 | 3,792 | 0.0020 | 0.9980 | 54.91 |
| 72.5 | 1,934,088 | | 0.0000 | 1.0000 | 54.81 |
| 73.5 | 1,934,088 | | 0.0000 | 1.0000 | 54.81 |
| 74.5 | 1,934,088 | | 0.0000 | 1.0000 | 54.81 |
| 75.5 | 1,934,088 | 43,598 | 0.0225 | 0.9775 | 54.81 |
| 76.5 | 1,890,490 | | 0.0000 | 1.0000 | 53.57 |
| 77.5 | 1,890,490 | | 0.0000 | 1.0000 | 53.57 |
| 78.5 | 1,890,490 | | 0.0000 | 1.0000 | 53.57 |

DUKE ENERGY PROGRESS

ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 1,890,490 | 121,054 | 0.0640 | 0.9360 | 53.57 |
| 80.5 | 1,769,436 | 1,851 | 0.0010 | 0.9990 | 50.14 |
| 81.5 | 1,767,585 | 3,698 | 0.0021 | 0.9979 | 50.09 |
| 82.5 | 1,763,887 | 180,820 | 0.1025 | 0.8975 | 49.98 |
| 83.5 | 1,583,067 | 13,100 | 0.0083 | 0.9917 | 44.86 |
| 84.5 | 1,569,967 | 374,682 | 0.2387 | 0.7613 | 44.49 |
| 85.5 | 1,195,285 | 10,882 | 0.0091 | 0.9909 | 33.87 |
| 86.5 | 1,184,403 | | 0.0000 | 1.0000 | 33.56 |
| 87.5 | 1,179,327 | 15,080 | 0.0128 | 0.9872 | 33.56 |
| 88.5 | 1,000,908 | 958 | 0.0010 | 0.9990 | 33.13 |
| 89.5 | 999,950 | 193 | 0.0002 | 0.9998 | 33.10 |
| 90.5 | 566,995 | 8,345 | 0.0147 | 0.9853 | 33.10 |
| 91.5 | 532,105 | | 0.0000 | 1.0000 | 32.61 |
| 92.5 | 532,105 | | 0.0000 | 1.0000 | 32.61 |
| 93.5 | 532,105 | | 0.0000 | 1.0000 | 32.61 |
| 94.5 | 532,105 | 7,828 | 0.0147 | 0.9853 | 32.61 |
| 95.5 | 499,346 | 1,970 | 0.0039 | 0.9961 | 32.13 |
| 96.5 | 491,109 | | 0.0000 | 1.0000 | 32.00 |
| 97.5 | 491,109 | | 0.0000 | 1.0000 | 32.00 |
| 98.5 | 491,109 | | 0.0000 | 1.0000 | 32.00 |
| 99.5 | 491,109 | | 0.0000 | 1.0000 | 32.00 |
| 100.5 | 478,793 | 111,372 | 0.2326 | 0.7674 | 32.00 |
| 101.5 | 367,421 | 3,082 | 0.0084 | 0.9916 | 24.56 |
| 102.5 | 364,339 | 86,632 | 0.2378 | 0.7622 | 24.35 |
| 103.5 | 277,707 | | 0.0000 | 1.0000 | 18.56 |
| 104.5 | 277,707 | | 0.0000 | 1.0000 | 18.56 |
| 105.5 | 277,707 | | 0.0000 | 1.0000 | 18.56 |
| 106.5 | 277,707 | 86,849 | 0.3127 | 0.6873 | 18.56 |
| 107.5 | 190,858 | 1,646 | 0.0086 | 0.9914 | 12.76 |
| 108.5 | | | | | 12.65 |

DUKE ENERGY PROGRESS

ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 36,942,616 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 35,143,517 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 28,664,833 | 296,203 | 0.0103 | 0.9897 | 100.00 |
| 2.5 | 28,405,327 | 87,285 | 0.0031 | 0.9969 | 98.97 |
| 3.5 | 28,147,490 | | 0.0000 | 1.0000 | 98.66 |
| 4.5 | 28,159,976 | | 0.0000 | 1.0000 | 98.66 |
| 5.5 | 23,003,574 | 650,642 | 0.0283 | 0.9717 | 98.66 |
| 6.5 | 16,862,565 | | 0.0000 | 1.0000 | 95.87 |
| 7.5 | 13,657,453 | | 0.0000 | 1.0000 | 95.87 |
| 8.5 | 13,642,779 | | 0.0000 | 1.0000 | 95.87 |
| 9.5 | 13,647,775 | | 0.0000 | 1.0000 | 95.87 |
| 10.5 | 13,647,781 | | 0.0000 | 1.0000 | 95.87 |
| 11.5 | 13,660,880 | | 0.0000 | 1.0000 | 95.87 |
| 12.5 | 13,609,881 | | 0.0000 | 1.0000 | 95.87 |
| 13.5 | 13,638,046 | | 0.0000 | 1.0000 | 95.87 |
| 14.5 | 13,686,293 | | 0.0000 | 1.0000 | 95.87 |
| 15.5 | 13,687,344 | 326 | 0.0000 | 1.0000 | 95.87 |
| 16.5 | 13,400,053 | 11,966 | 0.0009 | 0.9991 | 95.87 |
| 17.5 | 13,388,087 | 1,081 | 0.0001 | 0.9999 | 95.78 |
| 18.5 | 14,954,241 | | 0.0000 | 1.0000 | 95.78 |
| 19.5 | 15,381,161 | 15,597 | 0.0010 | 0.9990 | 95.78 |
| 20.5 | 15,356,668 | 561 | 0.0000 | 1.0000 | 95.68 |
| 21.5 | 15,011,049 | | 0.0000 | 1.0000 | 95.68 |
| 22.5 | 15,009,611 | 1,042 | 0.0001 | 0.9999 | 95.68 |
| 23.5 | 15,008,569 | 34,376 | 0.0023 | 0.9977 | 95.67 |
| 24.5 | 14,569,722 | 293,084 | 0.0201 | 0.9799 | 95.45 |
| 25.5 | 13,312,237 | 644,822 | 0.0484 | 0.9516 | 93.53 |
| 26.5 | 11,173,988 | 1,051 | 0.0001 | 0.9999 | 89.00 |
| 27.5 | 11,133,620 | 111,864 | 0.0100 | 0.9900 | 88.99 |
| 28.5 | 10,494,949 | 69,957 | 0.0067 | 0.9933 | 88.10 |
| 29.5 | 10,180,627 | 779 | 0.0001 | 0.9999 | 87.51 |
| 30.5 | 10,179,843 | 7,005 | 0.0007 | 0.9993 | 87.50 |
| 31.5 | 8,978,758 | 14,154 | 0.0016 | 0.9984 | 87.44 |
| 32.5 | 8,687,005 | 865,792 | 0.0997 | 0.9003 | 87.30 |
| 33.5 | 2,030,987 | 157 | 0.0001 | 0.9999 | 78.60 |
| 34.5 | 1,235,420 | 28,916 | 0.0234 | 0.9766 | 78.60 |
| 35.5 | 1,206,503 | 126 | 0.0001 | 0.9999 | 76.76 |
| 36.5 | 1,337,675 | 57,298 | 0.0428 | 0.9572 | 76.75 |
| 37.5 | 1,202,751 | | 0.0000 | 1.0000 | 73.46 |
| 38.5 | 1,161,055 | 438 | 0.0004 | 0.9996 | 73.46 |

DUKE ENERGY PROGRESS

ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 1,144,658 | | 0.0000 | 1.0000 | 73.43 |
| 40.5 | 1,144,658 | | 0.0000 | 1.0000 | 73.43 |
| 41.5 | 1,144,469 | 0 | 0.0000 | 1.0000 | 73.43 |
| 42.5 | 1,159,296 | | 0.0000 | 1.0000 | 73.43 |
| 43.5 | 1,159,296 | 0 | 0.0000 | 1.0000 | 73.43 |
| 44.5 | 1,158,422 | | 0.0000 | 1.0000 | 73.43 |
| 45.5 | 1,158,422 | 643 | 0.0006 | 0.9994 | 73.43 |
| 46.5 | 1,157,778 | 1,456 | 0.0013 | 0.9987 | 73.39 |
| 47.5 | 1,169,011 | 87 | 0.0001 | 0.9999 | 73.30 |
| 48.5 | 1,970,957 | 2,603 | 0.0013 | 0.9987 | 73.30 |
| 49.5 | 1,963,544 | 1,760 | 0.0009 | 0.9991 | 73.20 |
| 50.5 | 3,119,909 | | 0.0000 | 1.0000 | 73.13 |
| 51.5 | 3,143,707 | 1,245 | 0.0004 | 0.9996 | 73.13 |
| 52.5 | 3,142,462 | 12,399 | 0.0039 | 0.9961 | 73.10 |
| 53.5 | 3,130,036 | 14,827 | 0.0047 | 0.9953 | 72.82 |
| 54.5 | 3,102,964 | | 0.0000 | 1.0000 | 72.47 |
| 55.5 | 3,137,254 | 4,462 | 0.0014 | 0.9986 | 72.47 |
| 56.5 | 3,120,700 | | 0.0000 | 1.0000 | 72.37 |
| 57.5 | 3,120,700 | | 0.0000 | 1.0000 | 72.37 |
| 58.5 | 2,199,907 | | 0.0000 | 1.0000 | 72.37 |
| 59.5 | 2,199,907 | 572,720 | 0.2603 | 0.7397 | 72.37 |
| 60.5 | 1,639,503 | | 0.0000 | 1.0000 | 53.53 |
| 61.5 | 1,639,503 | | 0.0000 | 1.0000 | 53.53 |
| 62.5 | 1,639,503 | | 0.0000 | 1.0000 | 53.53 |
| 63.5 | 1,639,503 | 31,991 | 0.0195 | 0.9805 | 53.53 |
| 64.5 | 1,607,512 | 684 | 0.0004 | 0.9996 | 52.48 |
| 65.5 | 1,606,828 | | 0.0000 | 1.0000 | 52.46 |
| 66.5 | 1,607,968 | | 0.0000 | 1.0000 | 52.46 |
| 67.5 | 1,609,819 | 1,140 | 0.0007 | 0.9993 | 52.46 |
| 68.5 | 2,083,079 | 48,341 | 0.0232 | 0.9768 | 52.42 |
| 69.5 | 2,034,737 | 175 | 0.0001 | 0.9999 | 51.21 |
| 70.5 | 2,034,562 | 96,683 | 0.0475 | 0.9525 | 51.20 |
| 71.5 | 1,937,879 | 3,792 | 0.0020 | 0.9980 | 48.77 |
| 72.5 | 1,934,088 | | 0.0000 | 1.0000 | 48.67 |
| 73.5 | 1,934,088 | | 0.0000 | 1.0000 | 48.67 |
| 74.5 | 1,934,088 | | 0.0000 | 1.0000 | 48.67 |
| 75.5 | 1,934,088 | 43,598 | 0.0225 | 0.9775 | 48.67 |
| 76.5 | 1,890,490 | | 0.0000 | 1.0000 | 47.58 |
| 77.5 | 1,890,490 | | 0.0000 | 1.0000 | 47.58 |
| 78.5 | 1,890,490 | | 0.0000 | 1.0000 | 47.58 |

DUKE ENERGY PROGRESS

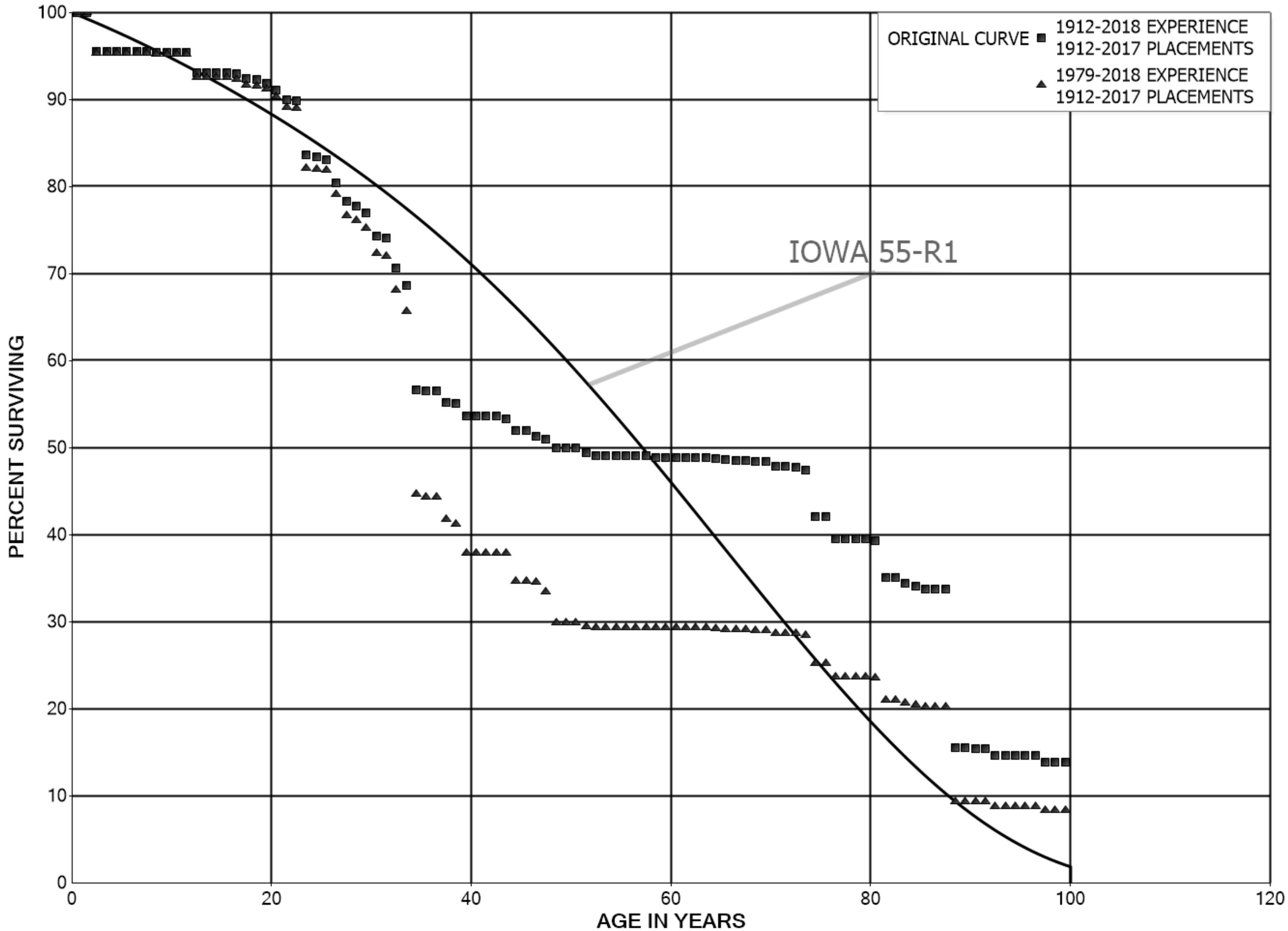
ACCOUNT 333 WATERWHEELS, TURBINES AND GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 1,890,490 | 121,054 | 0.0640 | 0.9360 | 47.58 |
| 80.5 | 1,769,436 | 1,851 | 0.0010 | 0.9990 | 44.53 |
| 81.5 | 1,767,585 | 3,698 | 0.0021 | 0.9979 | 44.48 |
| 82.5 | 1,763,887 | 180,820 | 0.1025 | 0.8975 | 44.39 |
| 83.5 | 1,583,067 | 13,100 | 0.0083 | 0.9917 | 39.84 |
| 84.5 | 1,569,967 | 374,682 | 0.2387 | 0.7613 | 39.51 |
| 85.5 | 1,195,285 | 10,882 | 0.0091 | 0.9909 | 30.08 |
| 86.5 | 1,184,403 | | 0.0000 | 1.0000 | 29.81 |
| 87.5 | 1,179,327 | 15,080 | 0.0128 | 0.9872 | 29.81 |
| 88.5 | 1,000,908 | 958 | 0.0010 | 0.9990 | 29.43 |
| 89.5 | 999,950 | 193 | 0.0002 | 0.9998 | 29.40 |
| 90.5 | 566,995 | 8,345 | 0.0147 | 0.9853 | 29.39 |
| 91.5 | 532,105 | | 0.0000 | 1.0000 | 28.96 |
| 92.5 | 532,105 | | 0.0000 | 1.0000 | 28.96 |
| 93.5 | 532,105 | | 0.0000 | 1.0000 | 28.96 |
| 94.5 | 532,105 | 7,828 | 0.0147 | 0.9853 | 28.96 |
| 95.5 | 499,346 | 1,970 | 0.0039 | 0.9961 | 28.53 |
| 96.5 | 491,109 | | 0.0000 | 1.0000 | 28.42 |
| 97.5 | 491,109 | | 0.0000 | 1.0000 | 28.42 |
| 98.5 | 491,109 | | 0.0000 | 1.0000 | 28.42 |
| 99.5 | 491,109 | | 0.0000 | 1.0000 | 28.42 |
| 100.5 | 478,793 | 111,372 | 0.2326 | 0.7674 | 28.42 |
| 101.5 | 367,421 | 3,082 | 0.0084 | 0.9916 | 21.81 |
| 102.5 | 364,339 | 86,632 | 0.2378 | 0.7622 | 21.63 |
| 103.5 | 277,707 | | 0.0000 | 1.0000 | 16.48 |
| 104.5 | 277,707 | | 0.0000 | 1.0000 | 16.48 |
| 105.5 | 277,707 | | 0.0000 | 1.0000 | 16.48 |
| 106.5 | 277,707 | 86,849 | 0.3127 | 0.6873 | 16.48 |
| 107.5 | 190,858 | 1,646 | 0.0086 | 0.9914 | 11.33 |
| 108.5 | | | | | 11.23 |

DUKE ENERGY PROGRESS
ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2017 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 27,879,238 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 27,909,171 | 6 | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 25,881,866 | 1,160,297 | 0.0448 | 0.9552 | 100.00 |
| 2.5 | 7,756,521 | | 0.0000 | 1.0000 | 95.52 |
| 3.5 | 7,961,795 | | 0.0000 | 1.0000 | 95.52 |
| 4.5 | 7,728,150 | 5 | 0.0000 | 1.0000 | 95.52 |
| 5.5 | 7,575,255 | 3 | 0.0000 | 1.0000 | 95.52 |
| 6.5 | 7,164,048 | 73 | 0.0000 | 1.0000 | 95.52 |
| 7.5 | 6,575,036 | 10,708 | 0.0016 | 0.9984 | 95.52 |
| 8.5 | 6,333,362 | 39 | 0.0000 | 1.0000 | 95.36 |
| 9.5 | 6,342,787 | | 0.0000 | 1.0000 | 95.36 |
| 10.5 | 6,342,787 | | 0.0000 | 1.0000 | 95.36 |
| 11.5 | 6,342,787 | 149,219 | 0.0235 | 0.9765 | 95.36 |
| 12.5 | 6,185,742 | | 0.0000 | 1.0000 | 93.12 |
| 13.5 | 6,185,742 | | 0.0000 | 1.0000 | 93.12 |
| 14.5 | 6,104,414 | 2,183 | 0.0004 | 0.9996 | 93.12 |
| 15.5 | 5,330,635 | 10,507 | 0.0020 | 0.9980 | 93.08 |
| 16.5 | 5,320,128 | 30,511 | 0.0057 | 0.9943 | 92.90 |
| 17.5 | 5,231,496 | 7,068 | 0.0014 | 0.9986 | 92.37 |
| 18.5 | 5,194,571 | 21,875 | 0.0042 | 0.9958 | 92.24 |
| 19.5 | 5,163,850 | 43,418 | 0.0084 | 0.9916 | 91.85 |
| 20.5 | 5,120,432 | 62,268 | 0.0122 | 0.9878 | 91.08 |
| 21.5 | 5,058,164 | 7,804 | 0.0015 | 0.9985 | 89.97 |
| 22.5 | 5,044,939 | 350,354 | 0.0694 | 0.9306 | 89.83 |
| 23.5 | 4,679,210 | 9,714 | 0.0021 | 0.9979 | 83.60 |
| 24.5 | 4,506,592 | 21,203 | 0.0047 | 0.9953 | 83.42 |
| 25.5 | 4,481,512 | 141,493 | 0.0316 | 0.9684 | 83.03 |
| 26.5 | 3,647,919 | 98,532 | 0.0270 | 0.9730 | 80.41 |
| 27.5 | 3,552,039 | 22,376 | 0.0063 | 0.9937 | 78.24 |
| 28.5 | 3,498,764 | 35,766 | 0.0102 | 0.9898 | 77.74 |
| 29.5 | 3,452,481 | 117,136 | 0.0339 | 0.9661 | 76.95 |
| 30.5 | 3,131,813 | 12,526 | 0.0040 | 0.9960 | 74.34 |
| 31.5 | 3,006,724 | 138,197 | 0.0460 | 0.9540 | 74.04 |
| 32.5 | 2,840,213 | 83,060 | 0.0292 | 0.9708 | 70.64 |
| 33.5 | 983,091 | 171,530 | 0.1745 | 0.8255 | 68.57 |
| 34.5 | 713,938 | 1,741 | 0.0024 | 0.9976 | 56.61 |
| 35.5 | 680,263 | 7 | 0.0000 | 1.0000 | 56.47 |
| 36.5 | 671,640 | 14,744 | 0.0220 | 0.9780 | 56.47 |
| 37.5 | 649,968 | 2,378 | 0.0037 | 0.9963 | 55.23 |
| 38.5 | 647,590 | 16,324 | 0.0252 | 0.9748 | 55.03 |

DUKE ENERGY PROGRESS

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2017 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 631,266 | 217 | 0.0003 | 0.9997 | 53.64 |
| 40.5 | 631,048 | | 0.0000 | 1.0000 | 53.62 |
| 41.5 | 631,048 | | 0.0000 | 1.0000 | 53.62 |
| 42.5 | 631,048 | 3,447 | 0.0055 | 0.9945 | 53.62 |
| 43.5 | 627,557 | 16,156 | 0.0257 | 0.9743 | 53.33 |
| 44.5 | 560,018 | | 0.0000 | 1.0000 | 51.96 |
| 45.5 | 560,018 | 6,836 | 0.0122 | 0.9878 | 51.96 |
| 46.5 | 537,040 | 3,496 | 0.0065 | 0.9935 | 51.32 |
| 47.5 | 533,544 | 10,760 | 0.0202 | 0.9798 | 50.99 |
| 48.5 | 522,784 | 238 | 0.0005 | 0.9995 | 49.96 |
| 49.5 | 522,546 | | 0.0000 | 1.0000 | 49.94 |
| 50.5 | 522,546 | 5,944 | 0.0114 | 0.9886 | 49.94 |
| 51.5 | 516,602 | 2,842 | 0.0055 | 0.9945 | 49.37 |
| 52.5 | 513,760 | | 0.0000 | 1.0000 | 49.10 |
| 53.5 | 513,760 | | 0.0000 | 1.0000 | 49.10 |
| 54.5 | 503,472 | 156 | 0.0003 | 0.9997 | 49.10 |
| 55.5 | 503,316 | | 0.0000 | 1.0000 | 49.08 |
| 56.5 | 503,316 | | 0.0000 | 1.0000 | 49.08 |
| 57.5 | 493,181 | 2,174 | 0.0044 | 0.9956 | 49.08 |
| 58.5 | 438,237 | 1 | 0.0000 | 1.0000 | 48.87 |
| 59.5 | 437,489 | | 0.0000 | 1.0000 | 48.87 |
| 60.5 | 437,489 | | 0.0000 | 1.0000 | 48.87 |
| 61.5 | 437,489 | 702 | 0.0016 | 0.9984 | 48.87 |
| 62.5 | 436,787 | | 0.0000 | 1.0000 | 48.79 |
| 63.5 | 436,787 | 98 | 0.0002 | 0.9998 | 48.79 |
| 64.5 | 436,689 | 1,903 | 0.0044 | 0.9956 | 48.78 |
| 65.5 | 434,786 | 86 | 0.0002 | 0.9998 | 48.56 |
| 66.5 | 434,700 | 4 | 0.0000 | 1.0000 | 48.55 |
| 67.5 | 432,879 | 1,894 | 0.0044 | 0.9956 | 48.55 |
| 68.5 | 430,985 | | 0.0000 | 1.0000 | 48.34 |
| 69.5 | 430,985 | 4,795 | 0.0111 | 0.9889 | 48.34 |
| 70.5 | 426,191 | | 0.0000 | 1.0000 | 47.80 |
| 71.5 | 426,191 | 806 | 0.0019 | 0.9981 | 47.80 |
| 72.5 | 425,385 | 2,422 | 0.0057 | 0.9943 | 47.71 |
| 73.5 | 422,963 | 47,679 | 0.1127 | 0.8873 | 47.44 |
| 74.5 | 374,524 | 701 | 0.0019 | 0.9981 | 42.09 |
| 75.5 | 373,601 | 22,524 | 0.0603 | 0.9397 | 42.01 |
| 76.5 | 351,077 | | 0.0000 | 1.0000 | 39.48 |
| 77.5 | 351,077 | | 0.0000 | 1.0000 | 39.48 |
| 78.5 | 351,077 | | 0.0000 | 1.0000 | 39.48 |

DUKE ENERGY PROGRESS

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2017 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 351,077 | 1,738 | 0.0049 | 0.9951 | 39.48 |
| 80.5 | 349,339 | 37,466 | 0.1072 | 0.8928 | 39.29 |
| 81.5 | 311,873 | | 0.0000 | 1.0000 | 35.07 |
| 82.5 | 311,873 | 5,819 | 0.0187 | 0.9813 | 35.07 |
| 83.5 | 306,054 | 3,271 | 0.0107 | 0.9893 | 34.42 |
| 84.5 | 302,782 | 3,271 | 0.0108 | 0.9892 | 34.05 |
| 85.5 | 299,511 | | 0.0000 | 1.0000 | 33.68 |
| 86.5 | 299,511 | | 0.0000 | 1.0000 | 33.68 |
| 87.5 | 299,511 | 161,910 | 0.5406 | 0.4594 | 33.68 |
| 88.5 | 137,602 | | 0.0000 | 1.0000 | 15.47 |
| 89.5 | 136,642 | 406 | 0.0030 | 0.9970 | 15.47 |
| 90.5 | 22,607 | | 0.0000 | 1.0000 | 15.43 |
| 91.5 | 22,607 | 1,254 | 0.0555 | 0.9445 | 15.43 |
| 92.5 | 21,352 | | 0.0000 | 1.0000 | 14.57 |
| 93.5 | 20,708 | | 0.0000 | 1.0000 | 14.57 |
| 94.5 | 20,708 | | 0.0000 | 1.0000 | 14.57 |
| 95.5 | 20,708 | | 0.0000 | 1.0000 | 14.57 |
| 96.5 | 20,708 | 1,014 | 0.0490 | 0.9510 | 14.57 |
| 97.5 | 19,694 | | 0.0000 | 1.0000 | 13.86 |
| 98.5 | 19,694 | | 0.0000 | 1.0000 | 13.86 |
| 99.5 | 19,694 | | 0.0000 | 1.0000 | 13.86 |
| 100.5 | 19,694 | | 0.0000 | 1.0000 | 13.86 |
| 101.5 | 19,210 | | 0.0000 | 1.0000 | 13.86 |
| 102.5 | 19,210 | | 0.0000 | 1.0000 | 13.86 |
| 103.5 | 19,210 | | 0.0000 | 1.0000 | 13.86 |
| 104.5 | 19,001 | 169 | 0.0089 | 0.9911 | 13.86 |
| 105.5 | 16,729 | 8,637 | 0.5163 | 0.4837 | 13.74 |
| 106.5 | | | | | 6.64 |

DUKE ENERGY PROGRESS

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2017 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 26,705,447 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 26,735,381 | 6 | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 24,713,308 | 1,160,297 | 0.0470 | 0.9530 | 100.00 |
| 2.5 | 6,591,569 | | 0.0000 | 1.0000 | 95.30 |
| 3.5 | 6,797,007 | | 0.0000 | 1.0000 | 95.30 |
| 4.5 | 6,669,599 | 5 | 0.0000 | 1.0000 | 95.30 |
| 5.5 | 6,519,092 | 3 | 0.0000 | 1.0000 | 95.30 |
| 6.5 | 6,139,209 | 73 | 0.0000 | 1.0000 | 95.30 |
| 7.5 | 5,551,521 | 7,033 | 0.0013 | 0.9987 | 95.30 |
| 8.5 | 5,318,108 | 39 | 0.0000 | 1.0000 | 95.18 |
| 9.5 | 5,327,534 | | 0.0000 | 1.0000 | 95.18 |
| 10.5 | 5,328,297 | | 0.0000 | 1.0000 | 95.18 |
| 11.5 | 5,333,327 | 147,377 | 0.0276 | 0.9724 | 95.18 |
| 12.5 | 5,306,674 | | 0.0000 | 1.0000 | 92.55 |
| 13.5 | 5,306,692 | | 0.0000 | 1.0000 | 92.55 |
| 14.5 | 5,269,219 | 2,183 | 0.0004 | 0.9996 | 92.55 |
| 15.5 | 4,495,964 | 10,507 | 0.0023 | 0.9977 | 92.51 |
| 16.5 | 4,485,457 | 30,511 | 0.0068 | 0.9932 | 92.30 |
| 17.5 | 4,413,133 | 5,556 | 0.0013 | 0.9987 | 91.67 |
| 18.5 | 4,458,002 | 20,520 | 0.0046 | 0.9954 | 91.55 |
| 19.5 | 4,685,127 | 43,418 | 0.0093 | 0.9907 | 91.13 |
| 20.5 | 4,641,708 | 62,268 | 0.0134 | 0.9866 | 90.29 |
| 21.5 | 4,579,440 | 7,804 | 0.0017 | 0.9983 | 89.08 |
| 22.5 | 4,569,711 | 350,354 | 0.0767 | 0.9233 | 88.93 |
| 23.5 | 4,203,982 | 9,714 | 0.0023 | 0.9977 | 82.11 |
| 24.5 | 4,031,365 | 1,911 | 0.0005 | 0.9995 | 81.92 |
| 25.5 | 4,025,576 | 138,418 | 0.0344 | 0.9656 | 81.88 |
| 26.5 | 3,195,058 | 98,532 | 0.0308 | 0.9692 | 79.06 |
| 27.5 | 3,101,000 | 22,376 | 0.0072 | 0.9928 | 76.63 |
| 28.5 | 3,047,725 | 35,766 | 0.0117 | 0.9883 | 76.07 |
| 29.5 | 3,001,540 | 117,136 | 0.0390 | 0.9610 | 75.18 |
| 30.5 | 2,680,872 | 12,444 | 0.0046 | 0.9954 | 72.25 |
| 31.5 | 2,555,865 | 138,197 | 0.0541 | 0.9459 | 71.91 |
| 32.5 | 2,390,588 | 82,765 | 0.0346 | 0.9654 | 68.02 |
| 33.5 | 533,846 | 171,530 | 0.3213 | 0.6787 | 65.67 |
| 34.5 | 265,453 | 1,741 | 0.0066 | 0.9934 | 44.57 |
| 35.5 | 232,000 | 7 | 0.0000 | 1.0000 | 44.28 |
| 36.5 | 223,378 | 12,969 | 0.0581 | 0.9419 | 44.27 |
| 37.5 | 203,482 | 2,378 | 0.0117 | 0.9883 | 41.70 |
| 38.5 | 201,104 | 16,324 | 0.0812 | 0.9188 | 41.22 |

DUKE ENERGY PROGRESS

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2017 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 184,780 | 7 | 0.0000 | 1.0000 | 37.87 |
| 40.5 | 186,510 | | 0.0000 | 1.0000 | 37.87 |
| 41.5 | 189,209 | | 0.0000 | 1.0000 | 37.87 |
| 42.5 | 189,209 | | 0.0000 | 1.0000 | 37.87 |
| 43.5 | 189,165 | 16,156 | 0.0854 | 0.9146 | 37.87 |
| 44.5 | 121,626 | | 0.0000 | 1.0000 | 34.63 |
| 45.5 | 121,626 | 491 | 0.0040 | 0.9960 | 34.63 |
| 46.5 | 105,492 | 3,496 | 0.0331 | 0.9669 | 34.49 |
| 47.5 | 101,996 | 10,760 | 0.1055 | 0.8945 | 33.35 |
| 48.5 | 303,248 | 238 | 0.0008 | 0.9992 | 29.83 |
| 49.5 | 304,671 | | 0.0000 | 1.0000 | 29.81 |
| 50.5 | 455,494 | 5,944 | 0.0130 | 0.9870 | 29.81 |
| 51.5 | 449,550 | 2,786 | 0.0062 | 0.9938 | 29.42 |
| 52.5 | 446,764 | | 0.0000 | 1.0000 | 29.24 |
| 53.5 | 447,408 | | 0.0000 | 1.0000 | 29.24 |
| 54.5 | 437,119 | | 0.0000 | 1.0000 | 29.24 |
| 55.5 | 438,456 | | 0.0000 | 1.0000 | 29.24 |
| 56.5 | 438,456 | | 0.0000 | 1.0000 | 29.24 |
| 57.5 | 429,336 | 97 | 0.0002 | 0.9998 | 29.24 |
| 58.5 | 376,469 | 1 | 0.0000 | 1.0000 | 29.23 |
| 59.5 | 375,721 | | 0.0000 | 1.0000 | 29.23 |
| 60.5 | 375,721 | | 0.0000 | 1.0000 | 29.23 |
| 61.5 | 376,205 | 1 | 0.0000 | 1.0000 | 29.23 |
| 62.5 | 376,203 | | 0.0000 | 1.0000 | 29.23 |
| 63.5 | 376,203 | 98 | 0.0003 | 0.9997 | 29.23 |
| 64.5 | 376,315 | 1,903 | 0.0051 | 0.9949 | 29.22 |
| 65.5 | 376,684 | 86 | 0.0002 | 0.9998 | 29.08 |
| 66.5 | 434,700 | 4 | 0.0000 | 1.0000 | 29.07 |
| 67.5 | 432,879 | 1,894 | 0.0044 | 0.9956 | 29.07 |
| 68.5 | 430,985 | | 0.0000 | 1.0000 | 28.94 |
| 69.5 | 430,985 | 4,795 | 0.0111 | 0.9889 | 28.94 |
| 70.5 | 426,191 | | 0.0000 | 1.0000 | 28.62 |
| 71.5 | 426,191 | 806 | 0.0019 | 0.9981 | 28.62 |
| 72.5 | 425,385 | 2,422 | 0.0057 | 0.9943 | 28.57 |
| 73.5 | 422,963 | 47,679 | 0.1127 | 0.8873 | 28.40 |
| 74.5 | 374,524 | 701 | 0.0019 | 0.9981 | 25.20 |
| 75.5 | 373,601 | 22,524 | 0.0603 | 0.9397 | 25.15 |
| 76.5 | 351,077 | | 0.0000 | 1.0000 | 23.64 |
| 77.5 | 351,077 | | 0.0000 | 1.0000 | 23.64 |
| 78.5 | 351,077 | | 0.0000 | 1.0000 | 23.64 |

DUKE ENERGY PROGRESS

ACCOUNT 334 ACCESSORY ELECTRIC EQUIPMENT

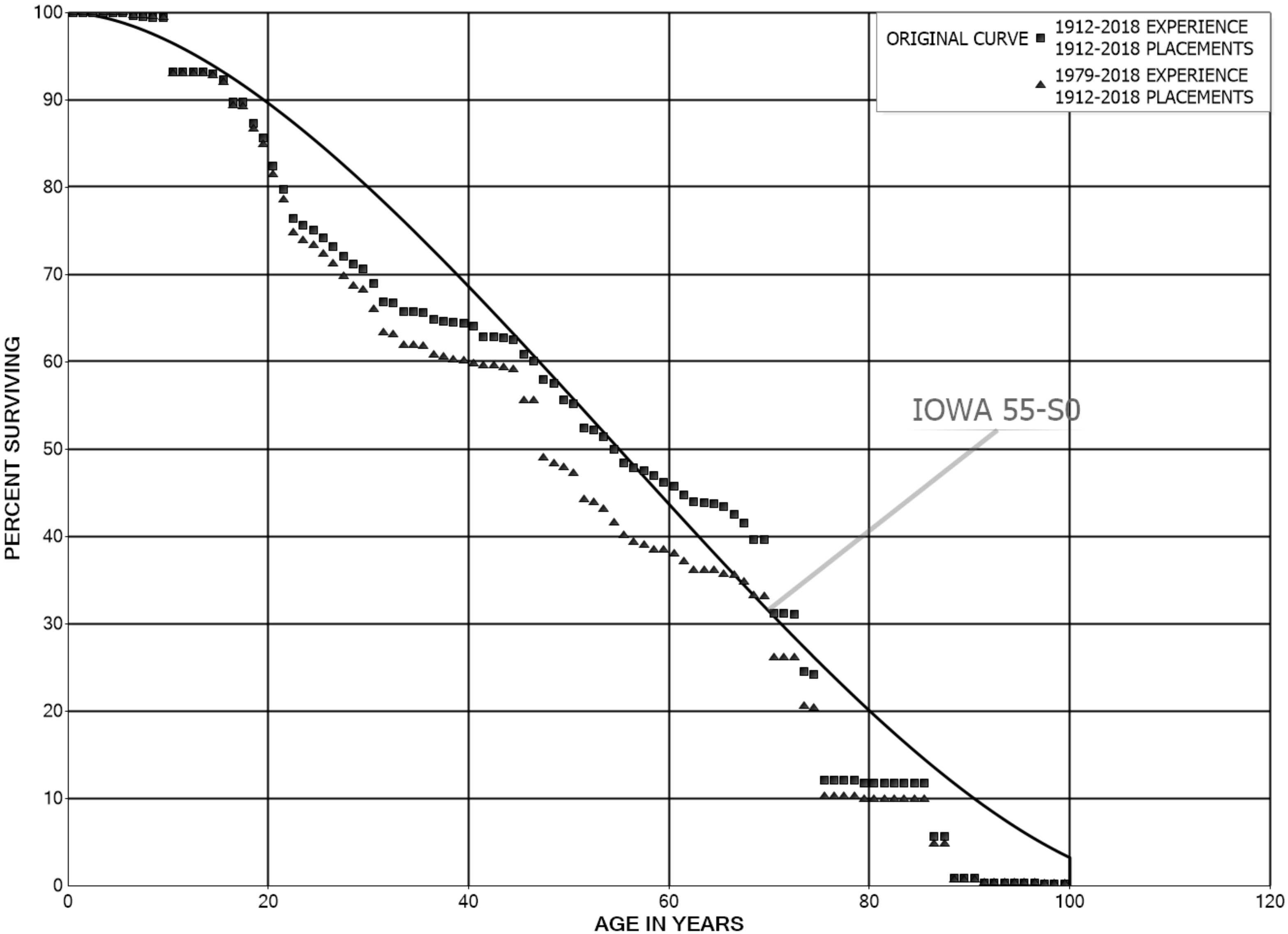
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2017 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 351,077 | 1,738 | 0.0049 | 0.9951 | 23.64 |
| 80.5 | 349,339 | 37,466 | 0.1072 | 0.8928 | 23.52 |
| 81.5 | 311,873 | | 0.0000 | 1.0000 | 21.00 |
| 82.5 | 311,873 | 5,819 | 0.0187 | 0.9813 | 21.00 |
| 83.5 | 306,054 | 3,271 | 0.0107 | 0.9893 | 20.61 |
| 84.5 | 302,782 | 3,271 | 0.0108 | 0.9892 | 20.39 |
| 85.5 | 299,511 | | 0.0000 | 1.0000 | 20.17 |
| 86.5 | 299,511 | | 0.0000 | 1.0000 | 20.17 |
| 87.5 | 299,511 | 161,910 | 0.5406 | 0.4594 | 20.17 |
| 88.5 | 137,602 | | 0.0000 | 1.0000 | 9.26 |
| 89.5 | 136,642 | 406 | 0.0030 | 0.9970 | 9.26 |
| 90.5 | 22,607 | | 0.0000 | 1.0000 | 9.24 |
| 91.5 | 22,607 | 1,254 | 0.0555 | 0.9445 | 9.24 |
| 92.5 | 21,352 | | 0.0000 | 1.0000 | 8.72 |
| 93.5 | 20,708 | | 0.0000 | 1.0000 | 8.72 |
| 94.5 | 20,708 | | 0.0000 | 1.0000 | 8.72 |
| 95.5 | 20,708 | | 0.0000 | 1.0000 | 8.72 |
| 96.5 | 20,708 | 1,014 | 0.0490 | 0.9510 | 8.72 |
| 97.5 | 19,694 | | 0.0000 | 1.0000 | 8.30 |
| 98.5 | 19,694 | | 0.0000 | 1.0000 | 8.30 |
| 99.5 | 19,694 | | 0.0000 | 1.0000 | 8.30 |
| 100.5 | 19,694 | | 0.0000 | 1.0000 | 8.30 |
| 101.5 | 19,210 | | 0.0000 | 1.0000 | 8.30 |
| 102.5 | 19,210 | | 0.0000 | 1.0000 | 8.30 |
| 103.5 | 19,210 | | 0.0000 | 1.0000 | 8.30 |
| 104.5 | 19,001 | 169 | 0.0089 | 0.9911 | 8.30 |
| 105.5 | 16,729 | 8,637 | 0.5163 | 0.4837 | 8.22 |
| 106.5 | | | | | 3.98 |

Gannett Fleming

DUKE ENERGY PROGRESS
ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 5,663,563 | 190 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 4,974,728 | 1,005 | 0.0002 | 0.9998 | 100.00 |
| 1.5 | 4,891,243 | | 0.0000 | 1.0000 | 99.98 |
| 2.5 | 4,463,051 | 1,541 | 0.0003 | 0.9997 | 99.98 |
| 3.5 | 4,449,948 | | 0.0000 | 1.0000 | 99.94 |
| 4.5 | 4,353,135 | 1,687 | 0.0004 | 0.9996 | 99.94 |
| 5.5 | 4,210,460 | 12,620 | 0.0030 | 0.9970 | 99.90 |
| 6.5 | 4,009,084 | 1,978 | 0.0005 | 0.9995 | 99.60 |
| 7.5 | 3,895,339 | 6,268 | 0.0016 | 0.9984 | 99.55 |
| 8.5 | 3,787,346 | 1,998 | 0.0005 | 0.9995 | 99.39 |
| 9.5 | 3,603,519 | 224,176 | 0.0622 | 0.9378 | 99.34 |
| 10.5 | 3,330,546 | | 0.0000 | 1.0000 | 93.16 |
| 11.5 | 3,246,928 | 930 | 0.0003 | 0.9997 | 93.16 |
| 12.5 | 3,174,216 | | 0.0000 | 1.0000 | 93.14 |
| 13.5 | 2,976,963 | 4,728 | 0.0016 | 0.9984 | 93.14 |
| 14.5 | 2,696,462 | 21,316 | 0.0079 | 0.9921 | 92.99 |
| 15.5 | 1,955,774 | 53,315 | 0.0273 | 0.9727 | 92.25 |
| 16.5 | 1,891,074 | 1,284 | 0.0007 | 0.9993 | 89.74 |
| 17.5 | 1,890,332 | 50,730 | 0.0268 | 0.9732 | 89.68 |
| 18.5 | 1,600,410 | 29,916 | 0.0187 | 0.9813 | 87.27 |
| 19.5 | 1,397,257 | 52,501 | 0.0376 | 0.9624 | 85.64 |
| 20.5 | 1,337,905 | 43,189 | 0.0323 | 0.9677 | 82.42 |
| 21.5 | 1,072,054 | 45,175 | 0.0421 | 0.9579 | 79.76 |
| 22.5 | 1,019,040 | 10,810 | 0.0106 | 0.9894 | 76.40 |
| 23.5 | 1,004,218 | 6,951 | 0.0069 | 0.9931 | 75.59 |
| 24.5 | 896,703 | 10,269 | 0.0115 | 0.9885 | 75.07 |
| 25.5 | 842,294 | 11,890 | 0.0141 | 0.9859 | 74.21 |
| 26.5 | 493,266 | 7,612 | 0.0154 | 0.9846 | 73.16 |
| 27.5 | 484,125 | 5,896 | 0.0122 | 0.9878 | 72.03 |
| 28.5 | 473,070 | 3,423 | 0.0072 | 0.9928 | 71.15 |
| 29.5 | 455,324 | 11,106 | 0.0244 | 0.9756 | 70.64 |
| 30.5 | 444,218 | 13,163 | 0.0296 | 0.9704 | 68.91 |
| 31.5 | 390,122 | 918 | 0.0024 | 0.9976 | 66.87 |
| 32.5 | 388,922 | 5,894 | 0.0152 | 0.9848 | 66.71 |
| 33.5 | 351,759 | 118 | 0.0003 | 0.9997 | 65.70 |
| 34.5 | 336,558 | 236 | 0.0007 | 0.9993 | 65.68 |
| 35.5 | 334,903 | 4,267 | 0.0127 | 0.9873 | 65.64 |
| 36.5 | 326,697 | 678 | 0.0021 | 0.9979 | 64.80 |
| 37.5 | 323,686 | 960 | 0.0030 | 0.9970 | 64.67 |
| 38.5 | 321,386 | 396 | 0.0012 | 0.9988 | 64.47 |

DUKE ENERGY PROGRESS

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 319,388 | 1,445 | 0.0045 | 0.9955 | 64.39 |
| 40.5 | 316,506 | 6,076 | 0.0192 | 0.9808 | 64.10 |
| 41.5 | 309,564 | 219 | 0.0007 | 0.9993 | 62.87 |
| 42.5 | 309,345 | 748 | 0.0024 | 0.9976 | 62.83 |
| 43.5 | 306,804 | 866 | 0.0028 | 0.9972 | 62.68 |
| 44.5 | 149,894 | 4,012 | 0.0268 | 0.9732 | 62.50 |
| 45.5 | 139,213 | 1,647 | 0.0118 | 0.9882 | 60.83 |
| 46.5 | 137,273 | 4,867 | 0.0355 | 0.9645 | 60.11 |
| 47.5 | 128,452 | 1,028 | 0.0080 | 0.9920 | 57.97 |
| 48.5 | 126,610 | 4,235 | 0.0334 | 0.9666 | 57.51 |
| 49.5 | 122,375 | 841 | 0.0069 | 0.9931 | 55.59 |
| 50.5 | 120,827 | 6,060 | 0.0502 | 0.9498 | 55.21 |
| 51.5 | 113,623 | 519 | 0.0046 | 0.9954 | 52.44 |
| 52.5 | 113,104 | 1,722 | 0.0152 | 0.9848 | 52.20 |
| 53.5 | 110,924 | 3,167 | 0.0285 | 0.9715 | 51.40 |
| 54.5 | 107,757 | 3,208 | 0.0298 | 0.9702 | 49.93 |
| 55.5 | 104,549 | 1,413 | 0.0135 | 0.9865 | 48.45 |
| 56.5 | 103,137 | 633 | 0.0061 | 0.9939 | 47.79 |
| 57.5 | 102,504 | 1,163 | 0.0113 | 0.9887 | 47.50 |
| 58.5 | 101,341 | 1,630 | 0.0161 | 0.9839 | 46.96 |
| 59.5 | 99,711 | 980 | 0.0098 | 0.9902 | 46.21 |
| 60.5 | 98,731 | 2,194 | 0.0222 | 0.9778 | 45.75 |
| 61.5 | 96,536 | 1,819 | 0.0188 | 0.9812 | 44.73 |
| 62.5 | 94,717 | 75 | 0.0008 | 0.9992 | 43.89 |
| 63.5 | 94,642 | 172 | 0.0018 | 0.9982 | 43.86 |
| 64.5 | 94,471 | 885 | 0.0094 | 0.9906 | 43.78 |
| 65.5 | 93,586 | 1,971 | 0.0211 | 0.9789 | 43.37 |
| 66.5 | 91,615 | 2,110 | 0.0230 | 0.9770 | 42.45 |
| 67.5 | 89,505 | 3,925 | 0.0438 | 0.9562 | 41.48 |
| 68.5 | 85,580 | 194 | 0.0023 | 0.9977 | 39.66 |
| 69.5 | 85,386 | 18,200 | 0.2131 | 0.7869 | 39.57 |
| 70.5 | 67,186 | | 0.0000 | 1.0000 | 31.13 |
| 71.5 | 67,186 | 31 | 0.0005 | 0.9995 | 31.13 |
| 72.5 | 67,155 | 14,264 | 0.2124 | 0.7876 | 31.12 |
| 73.5 | 52,891 | 718 | 0.0136 | 0.9864 | 24.51 |
| 74.5 | 52,173 | 26,048 | 0.4993 | 0.5007 | 24.18 |
| 75.5 | 26,125 | | 0.0000 | 1.0000 | 12.11 |
| 76.5 | 26,125 | | 0.0000 | 1.0000 | 12.11 |
| 77.5 | 26,125 | | 0.0000 | 1.0000 | 12.11 |
| 78.5 | 26,125 | 724 | 0.0277 | 0.9723 | 12.11 |

DUKE ENERGY PROGRESS

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1912-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 25,401 | | 0.0000 | 1.0000 | 11.77 |
| 80.5 | 25,401 | | 0.0000 | 1.0000 | 11.77 |
| 81.5 | 25,401 | | 0.0000 | 1.0000 | 11.77 |
| 82.5 | 25,401 | 7 | 0.0003 | 0.9997 | 11.77 |
| 83.5 | 25,394 | 40 | 0.0016 | 0.9984 | 11.77 |
| 84.5 | 25,354 | | 0.0000 | 1.0000 | 11.75 |
| 85.5 | 25,354 | 13,227 | 0.5217 | 0.4783 | 11.75 |
| 86.5 | 12,127 | | 0.0000 | 1.0000 | 5.62 |
| 87.5 | 12,127 | 10,441 | 0.8610 | 0.1390 | 5.62 |
| 88.5 | 1,686 | | 0.0000 | 1.0000 | 0.78 |
| 89.5 | 1,686 | | 0.0000 | 1.0000 | 0.78 |
| 90.5 | 1,686 | 953 | 0.5652 | 0.4348 | 0.78 |
| 91.5 | 733 | | 0.0000 | 1.0000 | 0.34 |
| 92.5 | 733 | | 0.0000 | 1.0000 | 0.34 |
| 93.5 | 733 | | 0.0000 | 1.0000 | 0.34 |
| 94.5 | 733 | | 0.0000 | 1.0000 | 0.34 |
| 95.5 | 733 | | 0.0000 | 1.0000 | 0.34 |
| 96.5 | 733 | 256 | 0.3492 | 0.6508 | 0.34 |
| 97.5 | 477 | | 0.0000 | 1.0000 | 0.22 |
| 98.5 | 477 | | 0.0000 | 1.0000 | 0.22 |
| 99.5 | 477 | | 0.0000 | 1.0000 | 0.22 |
| 100.5 | 477 | | 0.0000 | 1.0000 | 0.22 |
| 101.5 | 477 | | 0.0000 | 1.0000 | 0.22 |
| 102.5 | 477 | | 0.0000 | 1.0000 | 0.22 |
| 103.5 | 477 | 477 | 1.0000 | | 0.22 |
| 104.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 5,403,425 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 4,716,841 | 1,005 | 0.0002 | 0.9998 | 100.00 |
| 1.5 | 4,642,010 | | 0.0000 | 1.0000 | 99.98 |
| 2.5 | 4,222,445 | | 0.0000 | 1.0000 | 99.98 |
| 3.5 | 4,216,056 | | 0.0000 | 1.0000 | 99.98 |
| 4.5 | 4,145,316 | 1,687 | 0.0004 | 0.9996 | 99.98 |
| 5.5 | 4,021,088 | 11,280 | 0.0028 | 0.9972 | 99.94 |
| 6.5 | 3,822,721 | 1,469 | 0.0004 | 0.9996 | 99.66 |
| 7.5 | 3,727,700 | 6,268 | 0.0017 | 0.9983 | 99.62 |
| 8.5 | 3,621,843 | 1,998 | 0.0006 | 0.9994 | 99.45 |
| 9.5 | 3,443,198 | 224,162 | 0.0651 | 0.9349 | 99.40 |
| 10.5 | 3,176,850 | | 0.0000 | 1.0000 | 92.93 |
| 11.5 | 3,098,121 | 930 | 0.0003 | 0.9997 | 92.93 |
| 12.5 | 3,025,818 | | 0.0000 | 1.0000 | 92.90 |
| 13.5 | 2,833,463 | 4,728 | 0.0017 | 0.9983 | 92.90 |
| 14.5 | 2,555,430 | 21,316 | 0.0083 | 0.9917 | 92.74 |
| 15.5 | 1,816,352 | 53,315 | 0.0294 | 0.9706 | 91.97 |
| 16.5 | 1,751,786 | 1,105 | 0.0006 | 0.9994 | 89.27 |
| 17.5 | 1,754,861 | 50,532 | 0.0288 | 0.9712 | 89.21 |
| 18.5 | 1,472,364 | 29,916 | 0.0203 | 0.9797 | 86.64 |
| 19.5 | 1,273,918 | 52,501 | 0.0412 | 0.9588 | 84.88 |
| 20.5 | 1,215,907 | 43,189 | 0.0355 | 0.9645 | 81.39 |
| 21.5 | 950,851 | 45,175 | 0.0475 | 0.9525 | 78.50 |
| 22.5 | 897,884 | 10,710 | 0.0119 | 0.9881 | 74.77 |
| 23.5 | 883,359 | 6,951 | 0.0079 | 0.9921 | 73.87 |
| 24.5 | 777,772 | 10,269 | 0.0132 | 0.9868 | 73.29 |
| 25.5 | 723,749 | 11,890 | 0.0164 | 0.9836 | 72.32 |
| 26.5 | 375,203 | 7,612 | 0.0203 | 0.9797 | 71.14 |
| 27.5 | 367,027 | 5,727 | 0.0156 | 0.9844 | 69.69 |
| 28.5 | 356,257 | 2,524 | 0.0071 | 0.9929 | 68.61 |
| 29.5 | 342,351 | 11,106 | 0.0324 | 0.9676 | 68.12 |
| 30.5 | 334,033 | 13,163 | 0.0394 | 0.9606 | 65.91 |
| 31.5 | 281,543 | 918 | 0.0033 | 0.9967 | 63.31 |
| 32.5 | 280,354 | 5,571 | 0.0199 | 0.9801 | 63.11 |
| 33.5 | 243,651 | 118 | 0.0005 | 0.9995 | 61.85 |
| 34.5 | 228,449 | 236 | 0.0010 | 0.9990 | 61.82 |
| 35.5 | 226,967 | 3,957 | 0.0174 | 0.9826 | 61.76 |
| 36.5 | 220,427 | 678 | 0.0031 | 0.9969 | 60.68 |
| 37.5 | 217,866 | 960 | 0.0044 | 0.9956 | 60.50 |
| 38.5 | 215,566 | 396 | 0.0018 | 0.9982 | 60.23 |

DUKE ENERGY PROGRESS

ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 213,568 | 1,445 | 0.0068 | 0.9932 | 60.12 |
| 40.5 | 211,074 | 592 | 0.0028 | 0.9972 | 59.71 |
| 41.5 | 210,437 | 219 | 0.0010 | 0.9990 | 59.54 |
| 42.5 | 210,218 | 748 | 0.0036 | 0.9964 | 59.48 |
| 43.5 | 207,676 | 766 | 0.0037 | 0.9963 | 59.27 |
| 44.5 | 50,867 | 3,029 | 0.0595 | 0.9405 | 59.05 |
| 45.5 | 41,168 | | 0.0000 | 1.0000 | 55.53 |
| 46.5 | 40,915 | 4,867 | 0.1190 | 0.8810 | 55.53 |
| 47.5 | 32,125 | 397 | 0.0124 | 0.9876 | 48.93 |
| 48.5 | 58,292 | 559 | 0.0096 | 0.9904 | 48.32 |
| 49.5 | 57,747 | 841 | 0.0146 | 0.9854 | 47.86 |
| 50.5 | 94,830 | 6,060 | 0.0639 | 0.9361 | 47.16 |
| 51.5 | 87,627 | 519 | 0.0059 | 0.9941 | 44.15 |
| 52.5 | 87,108 | 1,722 | 0.0198 | 0.9802 | 43.89 |
| 53.5 | 84,928 | 2,962 | 0.0349 | 0.9651 | 43.02 |
| 54.5 | 81,966 | 2,938 | 0.0358 | 0.9642 | 41.52 |
| 55.5 | 79,028 | 1,413 | 0.0179 | 0.9821 | 40.03 |
| 56.5 | 77,615 | 633 | 0.0082 | 0.9918 | 39.32 |
| 57.5 | 76,982 | 1,163 | 0.0151 | 0.9849 | 39.00 |
| 58.5 | 75,819 | 7 | 0.0001 | 0.9999 | 38.41 |
| 59.5 | 76,499 | 793 | 0.0104 | 0.9896 | 38.40 |
| 60.5 | 75,706 | 1,954 | 0.0258 | 0.9742 | 38.00 |
| 61.5 | 73,752 | 1,819 | 0.0247 | 0.9753 | 37.02 |
| 62.5 | 71,933 | | 0.0000 | 1.0000 | 36.11 |
| 63.5 | 71,933 | 172 | 0.0024 | 0.9976 | 36.11 |
| 64.5 | 71,761 | 885 | 0.0123 | 0.9877 | 36.02 |
| 65.5 | 70,876 | 97 | 0.0014 | 0.9986 | 35.58 |
| 66.5 | 91,615 | 2,110 | 0.0230 | 0.9770 | 35.53 |
| 67.5 | 89,505 | 3,925 | 0.0438 | 0.9562 | 34.71 |
| 68.5 | 85,580 | 194 | 0.0023 | 0.9977 | 33.19 |
| 69.5 | 85,386 | 18,200 | 0.2131 | 0.7869 | 33.12 |
| 70.5 | 67,186 | | 0.0000 | 1.0000 | 26.06 |
| 71.5 | 67,186 | 31 | 0.0005 | 0.9995 | 26.06 |
| 72.5 | 67,155 | 14,264 | 0.2124 | 0.7876 | 26.04 |
| 73.5 | 52,891 | 718 | 0.0136 | 0.9864 | 20.51 |
| 74.5 | 52,173 | 26,048 | 0.4993 | 0.5007 | 20.23 |
| 75.5 | 26,125 | | 0.0000 | 1.0000 | 10.13 |
| 76.5 | 26,125 | | 0.0000 | 1.0000 | 10.13 |
| 77.5 | 26,125 | | 0.0000 | 1.0000 | 10.13 |
| 78.5 | 26,125 | 724 | 0.0277 | 0.9723 | 10.13 |

DUKE ENERGY PROGRESS

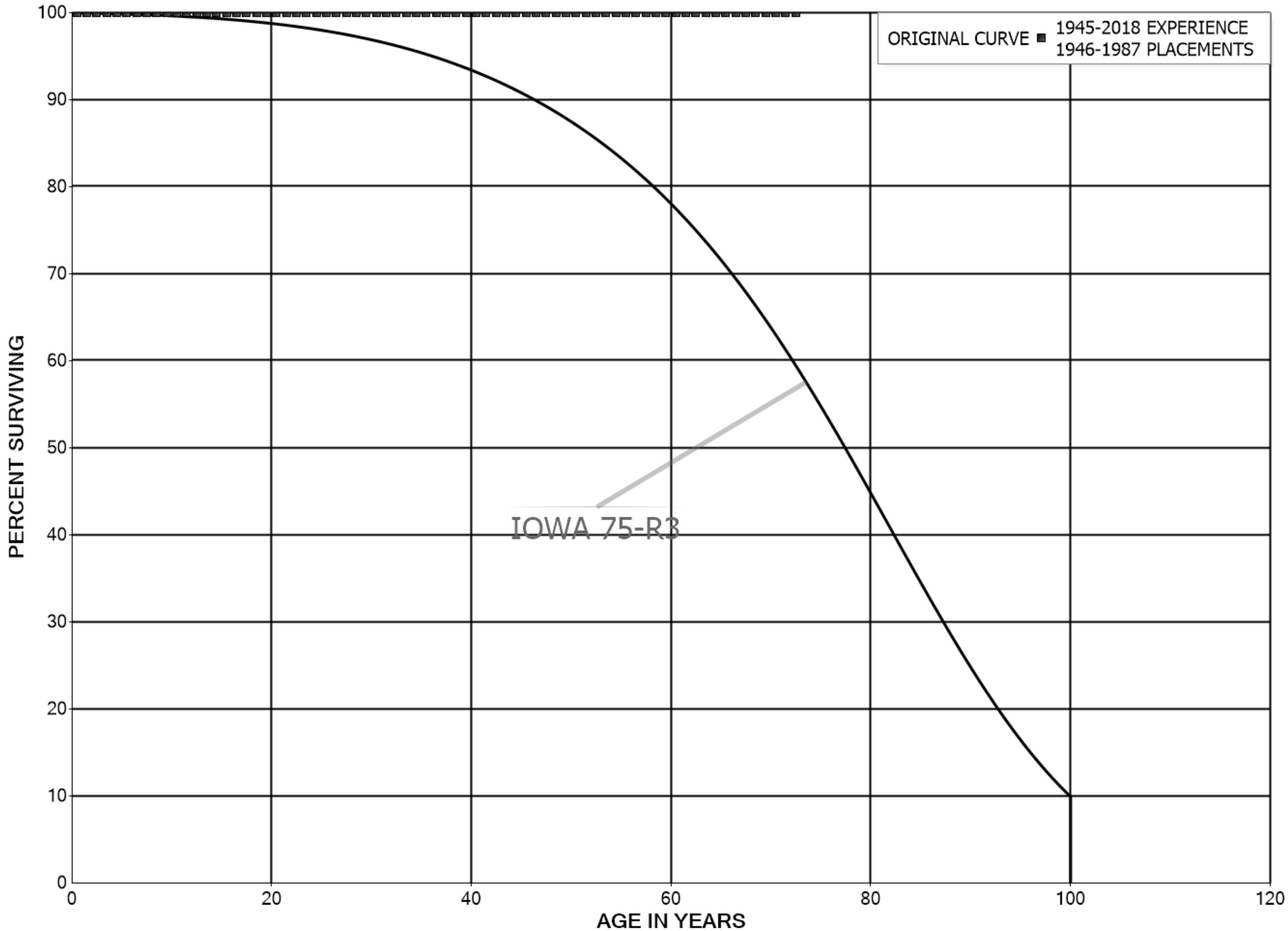
ACCOUNT 335 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 25,401 | | 0.0000 | 1.0000 | 9.85 |
| 80.5 | 25,401 | | 0.0000 | 1.0000 | 9.85 |
| 81.5 | 25,401 | | 0.0000 | 1.0000 | 9.85 |
| 82.5 | 25,401 | 7 | 0.0003 | 0.9997 | 9.85 |
| 83.5 | 25,394 | 40 | 0.0016 | 0.9984 | 9.85 |
| 84.5 | 25,354 | | 0.0000 | 1.0000 | 9.83 |
| 85.5 | 25,354 | 13,227 | 0.5217 | 0.4783 | 9.83 |
| 86.5 | 12,127 | | 0.0000 | 1.0000 | 4.70 |
| 87.5 | 12,127 | 10,441 | 0.8610 | 0.1390 | 4.70 |
| 88.5 | 1,686 | | 0.0000 | 1.0000 | 0.65 |
| 89.5 | 1,686 | | 0.0000 | 1.0000 | 0.65 |
| 90.5 | 1,686 | 953 | 0.5652 | 0.4348 | 0.65 |
| 91.5 | 733 | | 0.0000 | 1.0000 | 0.28 |
| 92.5 | 733 | | 0.0000 | 1.0000 | 0.28 |
| 93.5 | 733 | | 0.0000 | 1.0000 | 0.28 |
| 94.5 | 733 | | 0.0000 | 1.0000 | 0.28 |
| 95.5 | 733 | | 0.0000 | 1.0000 | 0.28 |
| 96.5 | 733 | 256 | 0.3492 | 0.6508 | 0.28 |
| 97.5 | 477 | | 0.0000 | 1.0000 | 0.18 |
| 98.5 | 477 | | 0.0000 | 1.0000 | 0.18 |
| 99.5 | 477 | | 0.0000 | 1.0000 | 0.18 |
| 100.5 | 477 | | 0.0000 | 1.0000 | 0.18 |
| 101.5 | 477 | | 0.0000 | 1.0000 | 0.18 |
| 102.5 | 477 | | 0.0000 | 1.0000 | 0.18 |
| 103.5 | 477 | 477 | 1.0000 | | 0.18 |
| 104.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 336 ROADS, RAILROADS AND BRIDGES
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 336 ROADS, RAILROADS AND BRIDGES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1946-1987 EXPERIENCE BAND 1945-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 17,671 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 17,671 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 17,671 | | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 17,671 | | 0.0000 | 1.0000 | 100.00 |
| 3.5 | 17,671 | | 0.0000 | 1.0000 | 100.00 |
| 4.5 | 17,671 | | 0.0000 | 1.0000 | 100.00 |
| 5.5 | 17,686 | | 0.0000 | 1.0000 | 100.00 |
| 6.5 | 17,905 | | 0.0000 | 1.0000 | 100.00 |
| 7.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 8.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 9.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 10.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 11.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 12.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 13.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 14.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 15.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 16.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 17.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 18.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 19.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 20.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 21.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 22.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 23.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 24.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 25.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 26.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 27.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 28.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 29.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 30.5 | 21,205 | | 0.0000 | 1.0000 | 100.00 |
| 31.5 | 21,166 | | 0.0000 | 1.0000 | 100.00 |
| 32.5 | 20,584 | | 0.0000 | 1.0000 | 100.00 |
| 33.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 34.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 35.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 36.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 37.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 38.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |

DUKE ENERGY PROGRESS

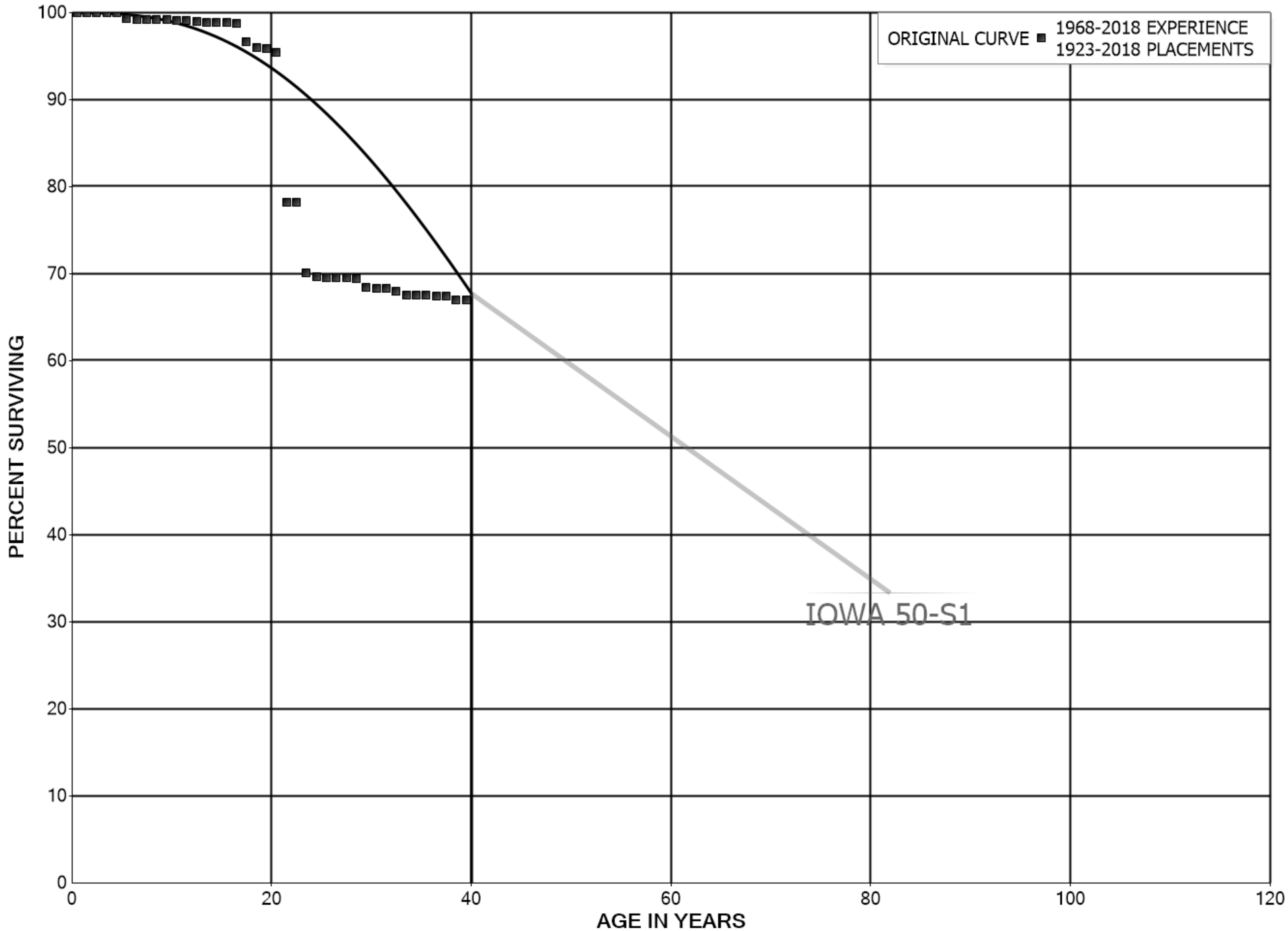
ACCOUNT 336 ROADS, RAILROADS AND BRIDGES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1946-1987 EXPERIENCE BAND 1945-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 40.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 41.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 42.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 43.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 44.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 45.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 46.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 47.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 48.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 49.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 50.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 51.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 52.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 53.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 54.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 55.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 56.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 57.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 58.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 59.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 60.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 61.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 62.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 63.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 64.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 65.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 66.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 67.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 68.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 69.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 70.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 71.5 | 8,258 | | 0.0000 | 1.0000 | 100.00 |
| 72.5 | | | | | 100.00 |

DUKE ENERGY PROGRESS
ACCOUNT 341 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 204,623,957 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 203,370,528 | 11,625 | 0.0001 | 0.9999 | 100.00 |
| 1.5 | 198,671,862 | 18,072 | 0.0001 | 0.9999 | 99.99 |
| 2.5 | 193,830,567 | 52,500 | 0.0003 | 0.9997 | 99.99 |
| 3.5 | 192,311,509 | 61,670 | 0.0003 | 0.9997 | 99.96 |
| 4.5 | 191,487,506 | 1,263,159 | 0.0066 | 0.9934 | 99.93 |
| 5.5 | 176,008,416 | 72,163 | 0.0004 | 0.9996 | 99.27 |
| 6.5 | 159,466,585 | 2,074 | 0.0000 | 1.0000 | 99.23 |
| 7.5 | 118,852,663 | 2,074 | 0.0000 | 1.0000 | 99.22 |
| 8.5 | 118,563,071 | 32,074 | 0.0003 | 0.9997 | 99.22 |
| 9.5 | 116,102,209 | 125,294 | 0.0011 | 0.9989 | 99.20 |
| 10.5 | 115,907,066 | 6,068 | 0.0001 | 0.9999 | 99.09 |
| 11.5 | 115,542,038 | 166,767 | 0.0014 | 0.9986 | 99.08 |
| 12.5 | 115,316,191 | 62,883 | 0.0005 | 0.9995 | 98.94 |
| 13.5 | 115,264,085 | 4,352 | 0.0000 | 1.0000 | 98.89 |
| 14.5 | 114,602,832 | 50,225 | 0.0004 | 0.9996 | 98.88 |
| 15.5 | 112,665,023 | 76,027 | 0.0007 | 0.9993 | 98.84 |
| 16.5 | 64,497,831 | 1,442,714 | 0.0224 | 0.9776 | 98.77 |
| 17.5 | 52,508,426 | 330,727 | 0.0063 | 0.9937 | 96.56 |
| 18.5 | 43,786,677 | 31,890 | 0.0007 | 0.9993 | 95.96 |
| 19.5 | 16,079,563 | 84,472 | 0.0053 | 0.9947 | 95.89 |
| 20.5 | 13,071,562 | 2,357,997 | 0.1804 | 0.8196 | 95.38 |
| 21.5 | 10,936,895 | 5,378 | 0.0005 | 0.9995 | 78.18 |
| 22.5 | 10,757,886 | 1,113,711 | 0.1035 | 0.8965 | 78.14 |
| 23.5 | 9,644,175 | 66,108 | 0.0069 | 0.9931 | 70.05 |
| 24.5 | 9,353,648 | 10,268 | 0.0011 | 0.9989 | 69.57 |
| 25.5 | 8,509,407 | | 0.0000 | 1.0000 | 69.49 |
| 26.5 | 8,512,104 | | 0.0000 | 1.0000 | 69.49 |
| 27.5 | 8,418,561 | 12,441 | 0.0015 | 0.9985 | 69.49 |
| 28.5 | 8,280,395 | 122,491 | 0.0148 | 0.9852 | 69.39 |
| 29.5 | 8,171,502 | 7,985 | 0.0010 | 0.9990 | 68.36 |
| 30.5 | 9,207,986 | | 0.0000 | 1.0000 | 68.30 |
| 31.5 | 9,185,097 | 50,012 | 0.0054 | 0.9946 | 68.30 |
| 32.5 | 9,135,856 | 49,389 | 0.0054 | 0.9946 | 67.92 |
| 33.5 | 11,171,525 | 389 | 0.0000 | 1.0000 | 67.56 |
| 34.5 | 12,463,731 | 15,475 | 0.0012 | 0.9988 | 67.55 |
| 35.5 | 11,116,250 | 6,549 | 0.0006 | 0.9994 | 67.47 |
| 36.5 | 7,624,104 | 4,287 | 0.0006 | 0.9994 | 67.43 |
| 37.5 | 7,865,352 | 55,285 | 0.0070 | 0.9930 | 67.39 |
| 38.5 | 7,552,638 | | 0.0000 | 1.0000 | 66.92 |

DUKE ENERGY PROGRESS

ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 5,371,010 | 133,895 | 0.0249 | 0.9751 | 66.92 |
| 40.5 | 5,209,833 | 14,592 | 0.0028 | 0.9972 | 65.25 |
| 41.5 | 4,553,496 | 118,235 | 0.0260 | 0.9740 | 65.07 |
| 42.5 | 4,574,589 | | 0.0000 | 1.0000 | 63.38 |
| 43.5 | 4,199,698 | 64,529 | 0.0154 | 0.9846 | 63.38 |
| 44.5 | 2,651,795 | | 0.0000 | 1.0000 | 62.40 |
| 45.5 | 2,420,878 | | 0.0000 | 1.0000 | 62.40 |
| 46.5 | 2,414,378 | | 0.0000 | 1.0000 | 62.40 |
| 47.5 | 1,177,240 | | 0.0000 | 1.0000 | 62.40 |
| 48.5 | 46,065 | | 0.0000 | 1.0000 | 62.40 |
| 49.5 | 233,087 | | 0.0000 | 1.0000 | 62.40 |
| 50.5 | 2,109,795 | | 0.0000 | 1.0000 | 62.40 |
| 51.5 | 2,109,795 | | 0.0000 | 1.0000 | 62.40 |
| 52.5 | 2,109,795 | | 0.0000 | 1.0000 | 62.40 |
| 53.5 | 2,109,795 | | 0.0000 | 1.0000 | 62.40 |
| 54.5 | 2,149,237 | | 0.0000 | 1.0000 | 62.40 |
| 55.5 | 1,876,855 | | 0.0000 | 1.0000 | 62.40 |
| 56.5 | 726,634 | | 0.0000 | 1.0000 | 62.40 |
| 57.5 | 474,879 | | 0.0000 | 1.0000 | 62.40 |
| 58.5 | 474,879 | | 0.0000 | 1.0000 | 62.40 |
| 59.5 | 483,125 | | 0.0000 | 1.0000 | 62.40 |
| 60.5 | 488,256 | | 0.0000 | 1.0000 | 62.40 |
| 61.5 | 1,022,199 | | 0.0000 | 1.0000 | 62.40 |
| 62.5 | 1,222,487 | | 0.0000 | 1.0000 | 62.40 |
| 63.5 | 767,229 | | 0.0000 | 1.0000 | 62.40 |
| 64.5 | 747,755 | | 0.0000 | 1.0000 | 62.40 |
| 65.5 | 845,134 | | 0.0000 | 1.0000 | 62.40 |
| 66.5 | 734,378 | | 0.0000 | 1.0000 | 62.40 |
| 67.5 | 200,288 | | 0.0000 | 1.0000 | 62.40 |
| 68.5 | 200,288 | | 0.0000 | 1.0000 | 62.40 |
| 69.5 | | | | | 62.40 |
| 70.5 | 21,358 | | 0.0000 | | |
| 71.5 | | | | | |
| 72.5 | | | | | |
| 73.5 | | | | | |
| 74.5 | | | | | |
| 75.5 | | | | | |
| 76.5 | | | | | |
| 77.5 | | | | | |
| 78.5 | | | | | |

DUKE ENERGY PROGRESS

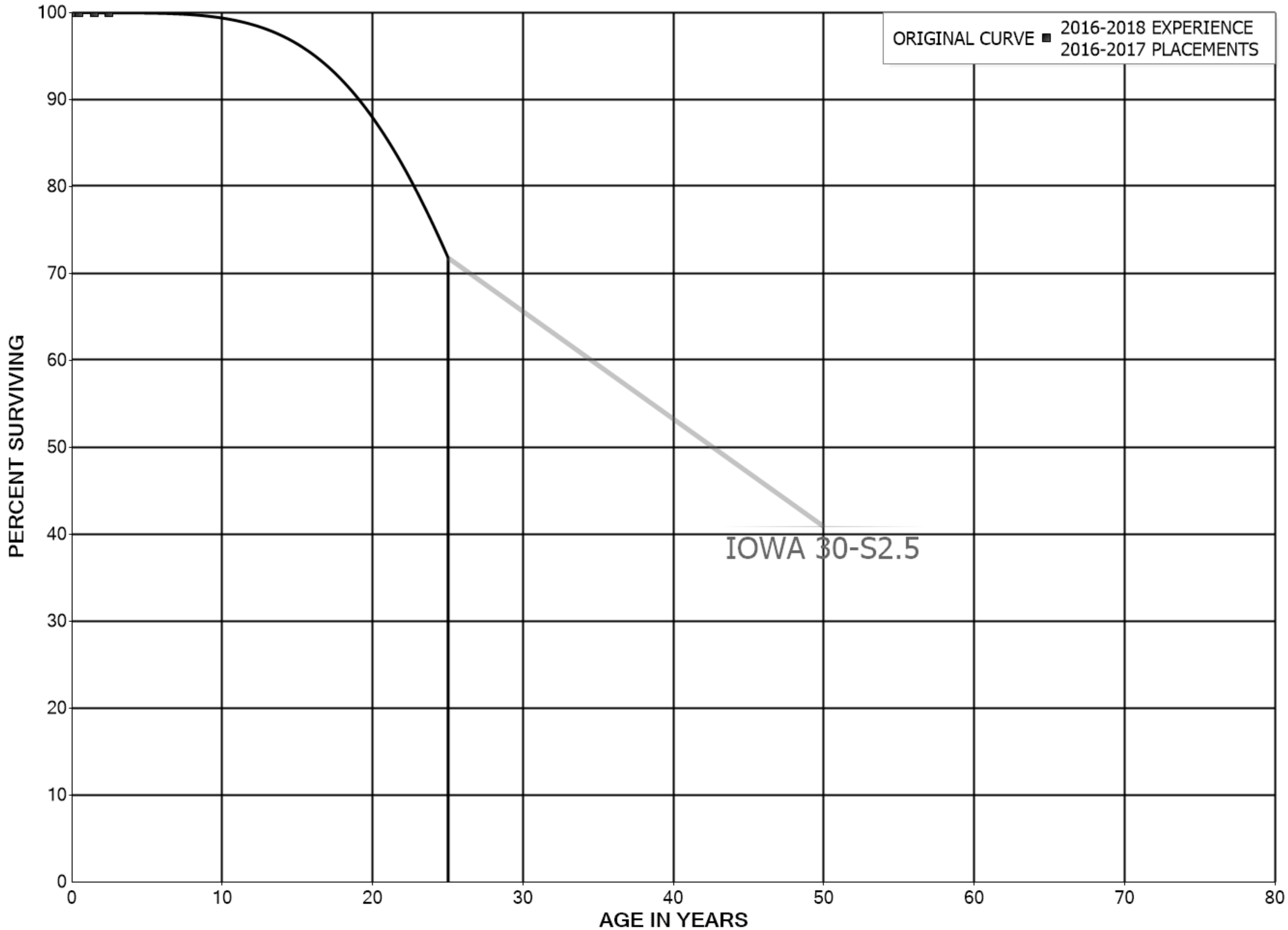
ACCOUNT 341 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | | | | | |
| 80.5 | | | | | |
| 81.5 | | | | | |
| 82.5 | | | | | |
| 83.5 | | | | | |
| 84.5 | | | | | |
| 85.5 | | | | | |
| 86.5 | 1,348 | | 0.0000 | | |
| 87.5 | | | | | |
| 88.5 | 15,004 | | 0.0000 | | |
| 89.5 | 16,753 | | 0.0000 | | |
| 90.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 341.2 STRUCTURES AND IMPROVEMENTS - SOLAR
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

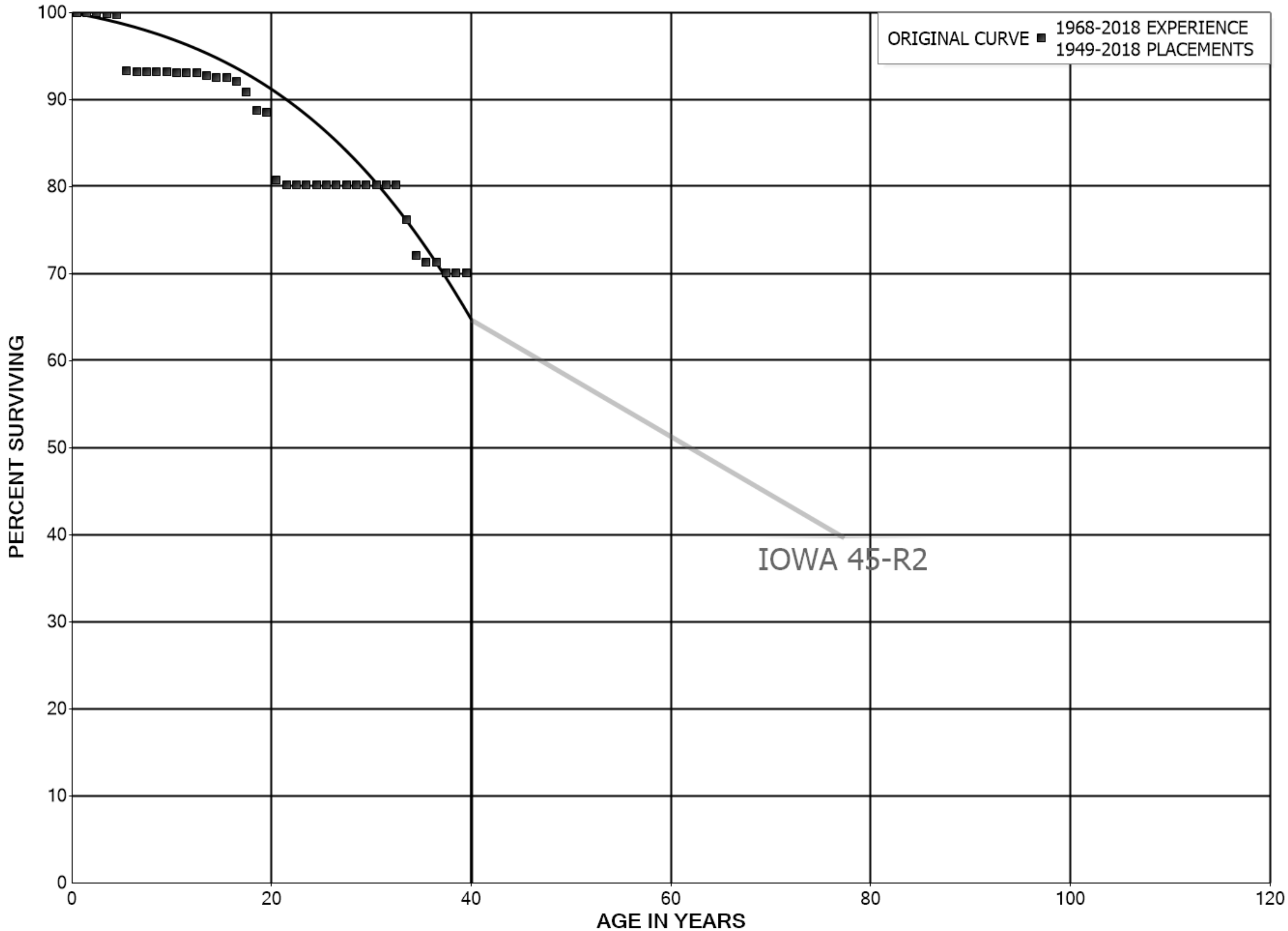
ACCOUNT 341.2 STRUCTURES AND IMPROVEMENTS - SOLAR

ORIGINAL LIFE TABLE

PLACEMENT BAND 2016-2017 EXPERIENCE BAND 2016-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 34,014 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 34,014 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 7,883 | | 0.0000 | 1.0000 | 100.00 |
| 2.5 | | | | | 100.00 |

DUKE ENERGY PROGRESS
ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 135,352,049 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 127,504,087 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 122,828,989 | 42,997 | 0.0004 | 0.9996 | 100.00 |
| 2.5 | 121,130,411 | 106,128 | 0.0009 | 0.9991 | 99.96 |
| 3.5 | 118,975,959 | 116,262 | 0.0010 | 0.9990 | 99.88 |
| 4.5 | 118,712,086 | 7,675,177 | 0.0647 | 0.9353 | 99.78 |
| 5.5 | 97,956,650 | 106,104 | 0.0011 | 0.9989 | 93.33 |
| 6.5 | 72,827,259 | 19,466 | 0.0003 | 0.9997 | 93.23 |
| 7.5 | 50,080,075 | 12,512 | 0.0002 | 0.9998 | 93.20 |
| 8.5 | 49,862,525 | 30,732 | 0.0006 | 0.9994 | 93.18 |
| 9.5 | 46,959,556 | 14,500 | 0.0003 | 0.9997 | 93.12 |
| 10.5 | 46,945,056 | 1,175 | 0.0000 | 1.0000 | 93.09 |
| 11.5 | 46,943,880 | 2,677 | 0.0001 | 0.9999 | 93.09 |
| 12.5 | 47,084,997 | 184,730 | 0.0039 | 0.9961 | 93.09 |
| 13.5 | 46,850,882 | 85,554 | 0.0018 | 0.9982 | 92.72 |
| 14.5 | 44,376,215 | | 0.0000 | 1.0000 | 92.55 |
| 15.5 | 43,954,564 | 208,566 | 0.0047 | 0.9953 | 92.55 |
| 16.5 | 30,539,068 | 413,162 | 0.0135 | 0.9865 | 92.11 |
| 17.5 | 22,588,548 | 538,257 | 0.0238 | 0.9762 | 90.87 |
| 18.5 | 16,299,266 | 31,197 | 0.0019 | 0.9981 | 88.70 |
| 19.5 | 13,090,896 | 1,150,431 | 0.0879 | 0.9121 | 88.53 |
| 20.5 | 10,730,470 | 72,213 | 0.0067 | 0.9933 | 80.75 |
| 21.5 | 10,651,951 | | 0.0000 | 1.0000 | 80.21 |
| 22.5 | 10,651,951 | | 0.0000 | 1.0000 | 80.21 |
| 23.5 | 10,503,351 | | 0.0000 | 1.0000 | 80.21 |
| 24.5 | 10,435,460 | | 0.0000 | 1.0000 | 80.21 |
| 25.5 | 10,414,591 | | 0.0000 | 1.0000 | 80.21 |
| 26.5 | 10,415,723 | 0 | 0.0000 | 1.0000 | 80.21 |
| 27.5 | 10,399,725 | 6,053 | 0.0006 | 0.9994 | 80.21 |
| 28.5 | 10,393,671 | 2,100 | 0.0002 | 0.9998 | 80.16 |
| 29.5 | 10,392,658 | 262 | 0.0000 | 1.0000 | 80.14 |
| 30.5 | 10,440,425 | 0 | 0.0000 | 1.0000 | 80.14 |
| 31.5 | 10,440,425 | 770 | 0.0001 | 0.9999 | 80.14 |
| 32.5 | 10,439,656 | 511,518 | 0.0490 | 0.9510 | 80.14 |
| 33.5 | 9,928,138 | 543,015 | 0.0547 | 0.9453 | 76.21 |
| 34.5 | 9,366,868 | 103,548 | 0.0111 | 0.9889 | 72.04 |
| 35.5 | 3,421,609 | 10 | 0.0000 | 1.0000 | 71.25 |
| 36.5 | 1,462,858 | 23,192 | 0.0159 | 0.9841 | 71.25 |
| 37.5 | 1,380,821 | 758 | 0.0005 | 0.9995 | 70.12 |
| 38.5 | 1,375,948 | 100 | 0.0001 | 0.9999 | 70.08 |

DUKE ENERGY PROGRESS

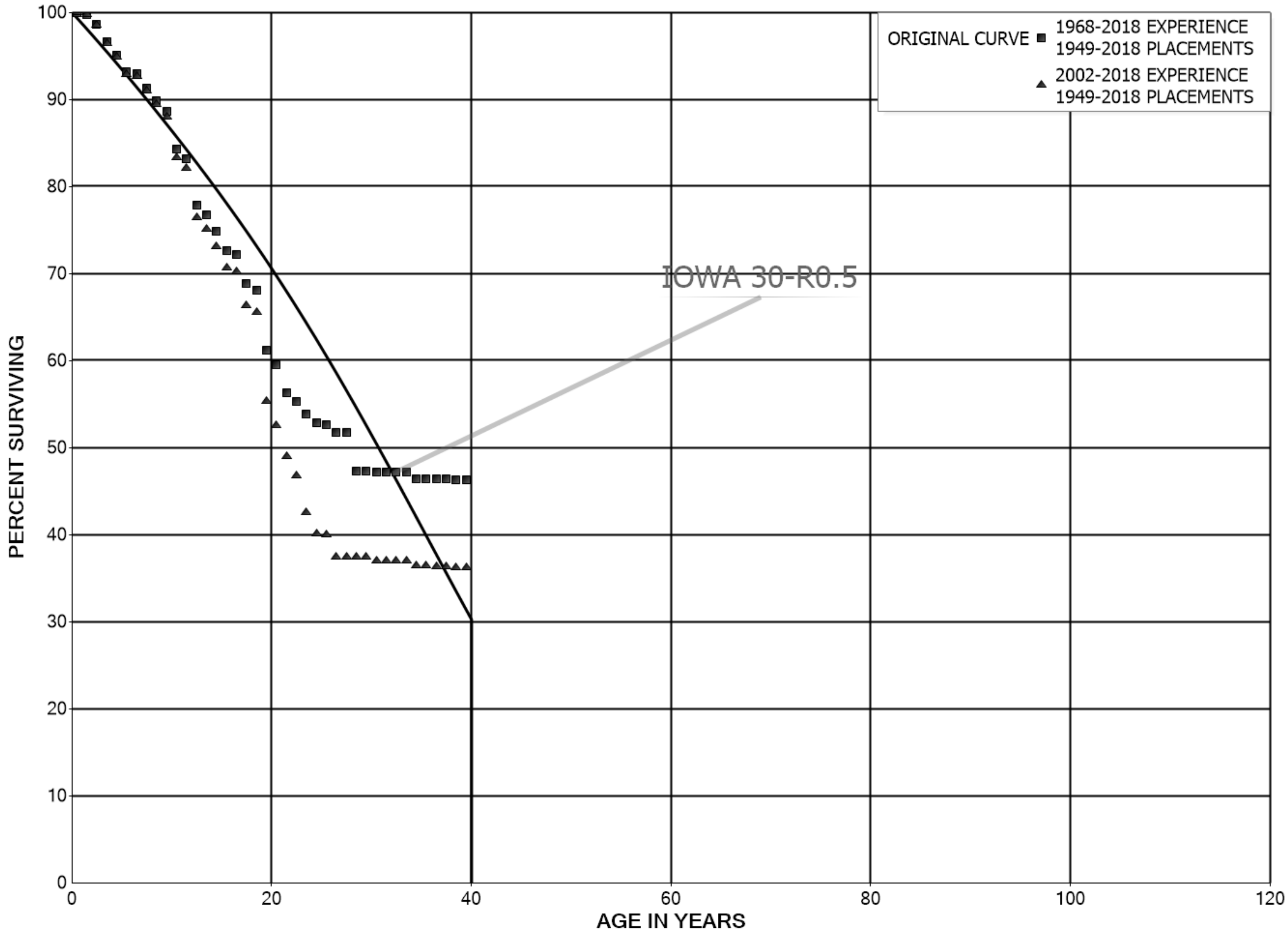
ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 1,355,250 | 18,317 | 0.0135 | 0.9865 | 70.07 |
| 40.5 | 1,336,934 | 46,888 | 0.0351 | 0.9649 | 69.12 |
| 41.5 | 1,056,220 | | 0.0000 | 1.0000 | 66.70 |
| 42.5 | 1,006,445 | | 0.0000 | 1.0000 | 66.70 |
| 43.5 | 954,565 | 23,996 | 0.0251 | 0.9749 | 66.70 |
| 44.5 | 810,941 | | 0.0000 | 1.0000 | 65.02 |
| 45.5 | 607,275 | | 0.0000 | 1.0000 | 65.02 |
| 46.5 | 605,744 | | 0.0000 | 1.0000 | 65.02 |
| 47.5 | 279,708 | 6,342 | 0.0227 | 0.9773 | 65.02 |
| 48.5 | 25,855 | | 0.0000 | 1.0000 | 63.55 |
| 49.5 | | | | | 63.55 |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | | | | | |
| 53.5 | | | | | |
| 54.5 | | | | | |
| 55.5 | | | | | |
| 56.5 | | | | | |
| 57.5 | | | | | |
| 58.5 | | | | | |
| 59.5 | | | | | |
| 60.5 | | | | | |
| 61.5 | | | | | |
| 62.5 | 18,653 | | 0.0000 | | |
| 63.5 | 18,653 | | 0.0000 | | |
| 64.5 | 18,653 | | 0.0000 | | |
| 65.5 | 18,653 | | 0.0000 | | |
| 66.5 | 18,653 | | 0.0000 | | |
| 67.5 | 18,653 | | 0.0000 | | |
| 68.5 | 18,653 | | 0.0000 | | |
| 69.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 343 PRIME MOVERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 343 PRIME MOVERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 2,198,785,684 | 517,057 | 0.0002 | 0.9998 | 100.00 |
| 0.5 | 2,088,910,875 | 5,178,376 | 0.0025 | 0.9975 | 99.98 |
| 1.5 | 1,960,183,509 | 22,171,606 | 0.0113 | 0.9887 | 99.73 |
| 2.5 | 1,910,030,082 | 39,397,679 | 0.0206 | 0.9794 | 98.60 |
| 3.5 | 1,824,484,748 | 29,276,040 | 0.0160 | 0.9840 | 96.57 |
| 4.5 | 1,749,318,289 | 33,776,942 | 0.0193 | 0.9807 | 95.02 |
| 5.5 | 1,310,753,819 | 4,109,020 | 0.0031 | 0.9969 | 93.18 |
| 6.5 | 816,282,127 | 13,705,661 | 0.0168 | 0.9832 | 92.89 |
| 7.5 | 480,103,478 | 7,697,852 | 0.0160 | 0.9840 | 91.33 |
| 8.5 | 466,894,545 | 6,604,782 | 0.0141 | 0.9859 | 89.87 |
| 9.5 | 405,928,121 | 19,700,189 | 0.0485 | 0.9515 | 88.60 |
| 10.5 | 374,379,094 | 5,124,170 | 0.0137 | 0.9863 | 84.30 |
| 11.5 | 355,694,811 | 22,562,962 | 0.0634 | 0.9366 | 83.14 |
| 12.5 | 325,627,214 | 4,969,075 | 0.0153 | 0.9847 | 77.87 |
| 13.5 | 318,449,354 | 7,854,014 | 0.0247 | 0.9753 | 76.68 |
| 14.5 | 304,005,489 | 9,006,680 | 0.0296 | 0.9704 | 74.79 |
| 15.5 | 278,836,374 | 1,390,726 | 0.0050 | 0.9950 | 72.57 |
| 16.5 | 206,506,756 | 9,759,856 | 0.0473 | 0.9527 | 72.21 |
| 17.5 | 150,958,858 | 1,531,978 | 0.0101 | 0.9899 | 68.80 |
| 18.5 | 75,719,740 | 7,730,369 | 0.1021 | 0.8979 | 68.10 |
| 19.5 | 61,976,296 | 1,706,471 | 0.0275 | 0.9725 | 61.15 |
| 20.5 | 51,740,969 | 2,758,505 | 0.0533 | 0.9467 | 59.46 |
| 21.5 | 44,131,559 | 828,148 | 0.0188 | 0.9812 | 56.29 |
| 22.5 | 35,477,191 | 922,743 | 0.0260 | 0.9740 | 55.24 |
| 23.5 | 32,695,341 | 571,599 | 0.0175 | 0.9825 | 53.80 |
| 24.5 | 31,100,492 | 157,061 | 0.0051 | 0.9949 | 52.86 |
| 25.5 | 30,819,087 | 525,883 | 0.0171 | 0.9829 | 52.59 |
| 26.5 | 30,293,203 | | 0.0000 | 1.0000 | 51.70 |
| 27.5 | 30,272,618 | 2,596,424 | 0.0858 | 0.9142 | 51.70 |
| 28.5 | 25,552,957 | | 0.0000 | 1.0000 | 47.26 |
| 29.5 | 25,552,957 | 55,183 | 0.0022 | 0.9978 | 47.26 |
| 30.5 | 25,480,403 | | 0.0000 | 1.0000 | 47.16 |
| 31.5 | 24,260,573 | 0 | 0.0000 | 1.0000 | 47.16 |
| 32.5 | 24,260,573 | | 0.0000 | 1.0000 | 47.16 |
| 33.5 | 24,215,972 | 366,022 | 0.0151 | 0.9849 | 47.16 |
| 34.5 | 23,741,196 | 11,894 | 0.0005 | 0.9995 | 46.45 |
| 35.5 | 23,397,489 | 36,275 | 0.0016 | 0.9984 | 46.42 |
| 36.5 | 23,343,992 | 2 | 0.0000 | 1.0000 | 46.35 |
| 37.5 | 23,178,716 | 53,477 | 0.0023 | 0.9977 | 46.35 |
| 38.5 | 23,099,358 | 4,794 | 0.0002 | 0.9998 | 46.24 |

DUKE ENERGY PROGRESS

ACCOUNT 343 PRIME MOVERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 22,482,611 | 1,276,915 | 0.0568 | 0.9432 | 46.23 |
| 40.5 | 21,159,011 | | 0.0000 | 1.0000 | 43.61 |
| 41.5 | 19,687,530 | 53,382 | 0.0027 | 0.9973 | 43.61 |
| 42.5 | 19,426,022 | 4,327 | 0.0002 | 0.9998 | 43.49 |
| 43.5 | 19,194,138 | 833,914 | 0.0434 | 0.9566 | 43.48 |
| 44.5 | 13,985,558 | | 0.0000 | 1.0000 | 41.59 |
| 45.5 | 12,844,183 | 20,716 | 0.0016 | 0.9984 | 41.59 |
| 46.5 | 12,821,705 | | 0.0000 | 1.0000 | 41.52 |
| 47.5 | 7,606,812 | | 0.0000 | 1.0000 | 41.52 |
| 48.5 | 1,097,911 | | 0.0000 | 1.0000 | 41.52 |
| 49.5 | | | | | 41.52 |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | | | | | |
| 53.5 | | | | | |
| 54.5 | | | | | |
| 55.5 | | | | | |
| 56.5 | 1,475 | | 0.0000 | | |
| 57.5 | 1,475 | | 0.0000 | | |
| 58.5 | 1,475 | | 0.0000 | | |
| 59.5 | 75,771 | | 0.0000 | | |
| 60.5 | 75,771 | | 0.0000 | | |
| 61.5 | 108,344 | | 0.0000 | | |
| 62.5 | 161,465 | | 0.0000 | | |
| 63.5 | 159,990 | | 0.0000 | | |
| 64.5 | 159,990 | | 0.0000 | | |
| 65.5 | 159,990 | | 0.0000 | | |
| 66.5 | 85,694 | | 0.0000 | | |
| 67.5 | 85,694 | | 0.0000 | | |
| 68.5 | 53,121 | | 0.0000 | | |
| 69.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 343 PRIME MOVERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 2002-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,857,315,357 | 4,076 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 1,852,626,606 | 5,178,376 | 0.0028 | 0.9972 | 100.00 |
| 1.5 | 1,845,981,239 | 22,157,371 | 0.0120 | 0.9880 | 99.72 |
| 2.5 | 1,815,569,593 | 39,397,679 | 0.0217 | 0.9783 | 98.52 |
| 3.5 | 1,759,830,018 | 29,276,040 | 0.0166 | 0.9834 | 96.39 |
| 4.5 | 1,688,400,276 | 33,776,942 | 0.0200 | 0.9800 | 94.78 |
| 5.5 | 1,264,130,598 | 4,109,020 | 0.0033 | 0.9967 | 92.89 |
| 6.5 | 775,522,204 | 13,705,661 | 0.0177 | 0.9823 | 92.58 |
| 7.5 | 440,338,858 | 7,647,852 | 0.0174 | 0.9826 | 90.95 |
| 8.5 | 427,332,216 | 6,604,782 | 0.0155 | 0.9845 | 89.37 |
| 9.5 | 367,725,514 | 19,700,189 | 0.0536 | 0.9464 | 87.99 |
| 10.5 | 338,626,301 | 4,938,402 | 0.0146 | 0.9854 | 83.27 |
| 11.5 | 323,073,571 | 22,505,541 | 0.0697 | 0.9303 | 82.06 |
| 12.5 | 293,390,519 | 4,871,075 | 0.0166 | 0.9834 | 76.34 |
| 13.5 | 286,319,754 | 7,808,407 | 0.0273 | 0.9727 | 75.07 |
| 14.5 | 272,973,345 | 9,006,680 | 0.0330 | 0.9670 | 73.03 |
| 15.5 | 247,804,231 | 1,390,726 | 0.0056 | 0.9944 | 70.62 |
| 16.5 | 176,527,920 | 9,759,856 | 0.0553 | 0.9447 | 70.22 |
| 17.5 | 121,467,649 | 1,531,398 | 0.0126 | 0.9874 | 66.34 |
| 18.5 | 46,559,566 | 7,269,014 | 0.1561 | 0.8439 | 65.50 |
| 19.5 | 34,458,906 | 1,706,471 | 0.0495 | 0.9505 | 55.28 |
| 20.5 | 24,422,599 | 1,657,921 | 0.0679 | 0.9321 | 52.54 |
| 21.5 | 17,983,676 | 828,148 | 0.0460 | 0.9540 | 48.97 |
| 22.5 | 9,465,818 | 858,501 | 0.0907 | 0.9093 | 46.72 |
| 23.5 | 6,748,210 | 378,874 | 0.0561 | 0.9439 | 42.48 |
| 24.5 | 5,350,949 | 16,390 | 0.0031 | 0.9969 | 40.10 |
| 25.5 | 5,509,740 | 360,458 | 0.0654 | 0.9346 | 39.97 |
| 26.5 | 5,187,911 | | 0.0000 | 1.0000 | 37.36 |
| 27.5 | 5,167,906 | | 0.0000 | 1.0000 | 37.36 |
| 28.5 | 3,554,499 | | 0.0000 | 1.0000 | 37.36 |
| 29.5 | 3,602,946 | 40,948 | 0.0114 | 0.9886 | 37.36 |
| 30.5 | 10,252,464 | | 0.0000 | 1.0000 | 36.93 |
| 31.5 | 12,457,766 | 0 | 0.0000 | 1.0000 | 36.93 |
| 32.5 | 18,814,452 | | 0.0000 | 1.0000 | 36.93 |
| 33.5 | 24,215,972 | 366,022 | 0.0151 | 0.9849 | 36.93 |
| 34.5 | 23,741,196 | 11,894 | 0.0005 | 0.9995 | 36.37 |
| 35.5 | 23,397,489 | 36,275 | 0.0016 | 0.9984 | 36.36 |
| 36.5 | 23,343,992 | 2 | 0.0000 | 1.0000 | 36.30 |
| 37.5 | 23,178,716 | 53,477 | 0.0023 | 0.9977 | 36.30 |
| 38.5 | 23,099,358 | 4,794 | 0.0002 | 0.9998 | 36.22 |

DUKE ENERGY PROGRESS

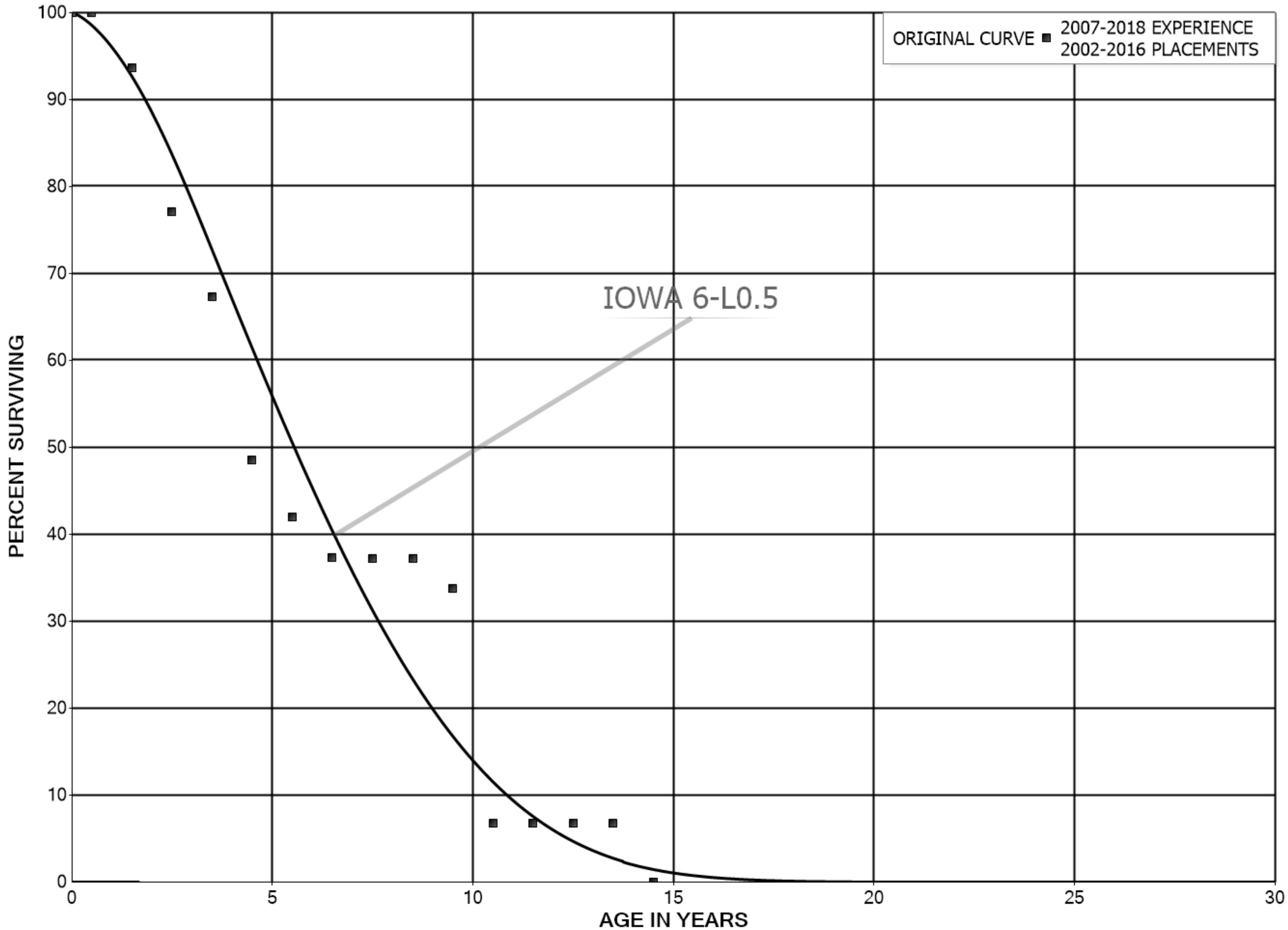
ACCOUNT 343 PRIME MOVERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2018 EXPERIENCE BAND 2002-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 22,482,611 | 1,276,915 | 0.0568 | 0.9432 | 36.21 |
| 40.5 | 21,159,011 | | 0.0000 | 1.0000 | 34.15 |
| 41.5 | 19,687,530 | 53,382 | 0.0027 | 0.9973 | 34.15 |
| 42.5 | 19,426,022 | 4,327 | 0.0002 | 0.9998 | 34.06 |
| 43.5 | 19,194,138 | 833,914 | 0.0434 | 0.9566 | 34.05 |
| 44.5 | 13,985,558 | | 0.0000 | 1.0000 | 32.57 |
| 45.5 | 12,844,183 | 20,716 | 0.0016 | 0.9984 | 32.57 |
| 46.5 | 12,821,705 | | 0.0000 | 1.0000 | 32.52 |
| 47.5 | 7,606,812 | | 0.0000 | 1.0000 | 32.52 |
| 48.5 | 1,097,911 | | 0.0000 | 1.0000 | 32.52 |
| 49.5 | | | | | 32.52 |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | | | | | |
| 53.5 | | | | | |
| 54.5 | | | | | |
| 55.5 | | | | | |
| 56.5 | 1,475 | | 0.0000 | | |
| 57.5 | 1,475 | | 0.0000 | | |
| 58.5 | 1,475 | | 0.0000 | | |
| 59.5 | 75,771 | | 0.0000 | | |
| 60.5 | 75,771 | | 0.0000 | | |
| 61.5 | 108,344 | | 0.0000 | | |
| 62.5 | 161,465 | | 0.0000 | | |
| 63.5 | 159,990 | | 0.0000 | | |
| 64.5 | 159,990 | | 0.0000 | | |
| 65.5 | 159,990 | | 0.0000 | | |
| 66.5 | 85,694 | | 0.0000 | | |
| 67.5 | 85,694 | | 0.0000 | | |
| 68.5 | 53,121 | | 0.0000 | | |
| 69.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 343.1 PRIME MOVERS - ROTABLE PARTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

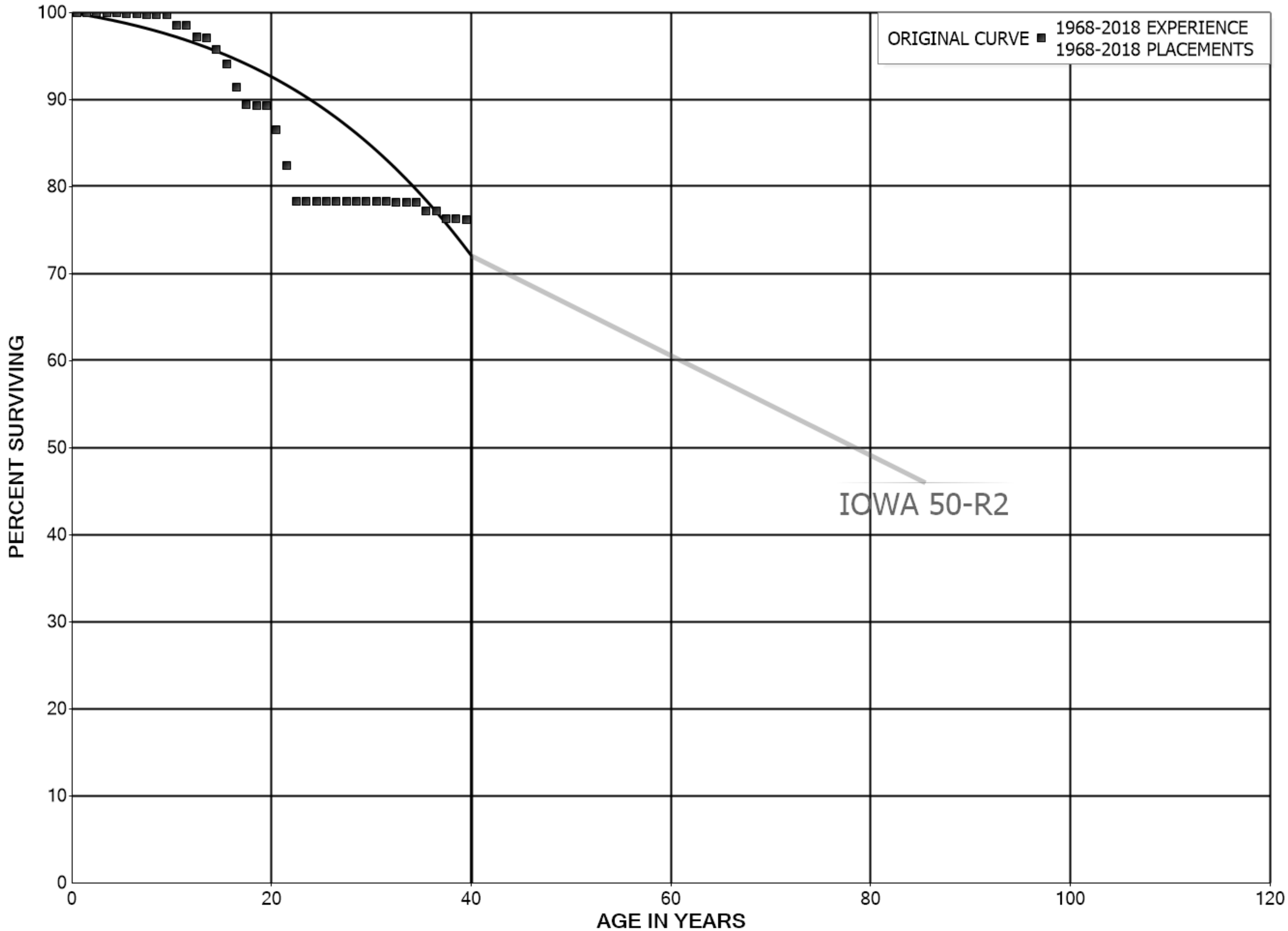
ACCOUNT 343.1 PRIME MOVERS - ROTABLE PARTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 2002-2016 EXPERIENCE BAND 2007-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 295,925,697 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 298,377,985 | 19,074,417 | 0.0639 | 0.9361 | 100.00 |
| 1.5 | 279,303,567 | 49,221,592 | 0.1762 | 0.8238 | 93.61 |
| 2.5 | 149,720,713 | 19,068,114 | 0.1274 | 0.8726 | 77.11 |
| 3.5 | 116,870,598 | 32,539,954 | 0.2784 | 0.7216 | 67.29 |
| 4.5 | 132,521,572 | 18,150,631 | 0.1370 | 0.8630 | 48.55 |
| 5.5 | 71,968,790 | 7,949,867 | 0.1105 | 0.8895 | 41.90 |
| 6.5 | 64,018,923 | 81,720 | 0.0013 | 0.9987 | 37.28 |
| 7.5 | 56,382,074 | | 0.0000 | 1.0000 | 37.23 |
| 8.5 | 56,382,074 | 5,315,555 | 0.0943 | 0.9057 | 37.23 |
| 9.5 | 51,066,518 | 40,827,472 | 0.7995 | 0.2005 | 33.72 |
| 10.5 | 10,239,046 | | 0.0000 | 1.0000 | 6.76 |
| 11.5 | 10,239,046 | | 0.0000 | 1.0000 | 6.76 |
| 12.5 | 10,239,046 | | 0.0000 | 1.0000 | 6.76 |
| 13.5 | 10,239,046 | 10,239,046 | 1.0000 | | 6.76 |
| 14.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 344 GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 344 GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 317,900,685 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 316,610,901 | 9,517 | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 314,229,805 | 8,587 | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 306,264,171 | | 0.0000 | 1.0000 | 99.99 |
| 3.5 | 301,003,794 | 150,474 | 0.0005 | 0.9995 | 99.99 |
| 4.5 | 299,995,700 | 458,368 | 0.0015 | 0.9985 | 99.94 |
| 5.5 | 252,873,184 | 12,610 | 0.0000 | 1.0000 | 99.79 |
| 6.5 | 196,436,767 | 100,639 | 0.0005 | 0.9995 | 99.79 |
| 7.5 | 164,618,519 | 60,522 | 0.0004 | 0.9996 | 99.74 |
| 8.5 | 163,180,860 | | 0.0000 | 1.0000 | 99.70 |
| 9.5 | 150,239,461 | 1,773,249 | 0.0118 | 0.9882 | 99.70 |
| 10.5 | 148,423,897 | | 0.0000 | 1.0000 | 98.52 |
| 11.5 | 148,423,897 | 2,087,350 | 0.0141 | 0.9859 | 98.52 |
| 12.5 | 145,693,197 | 26,549 | 0.0002 | 0.9998 | 97.14 |
| 13.5 | 145,666,648 | 2,138,506 | 0.0147 | 0.9853 | 97.12 |
| 14.5 | 143,490,043 | 2,481,828 | 0.0173 | 0.9827 | 95.69 |
| 15.5 | 129,842,713 | 3,654,555 | 0.0281 | 0.9719 | 94.04 |
| 16.5 | 87,051,157 | 1,913,433 | 0.0220 | 0.9780 | 91.39 |
| 17.5 | 61,521,313 | 32,717 | 0.0005 | 0.9995 | 89.38 |
| 18.5 | 34,275,199 | | 0.0000 | 1.0000 | 89.33 |
| 19.5 | 32,691,831 | 1,054,407 | 0.0323 | 0.9677 | 89.33 |
| 20.5 | 20,472,547 | 968,182 | 0.0473 | 0.9527 | 86.45 |
| 21.5 | 19,504,365 | 968,182 | 0.0496 | 0.9504 | 82.36 |
| 22.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 23.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 24.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 25.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 26.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 27.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 28.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 29.5 | 11,615,803 | | 0.0000 | 1.0000 | 78.28 |
| 30.5 | 11,615,803 | 463 | 0.0000 | 1.0000 | 78.28 |
| 31.5 | 11,615,340 | 13,219 | 0.0011 | 0.9989 | 78.27 |
| 32.5 | 11,602,121 | | 0.0000 | 1.0000 | 78.18 |
| 33.5 | 11,602,121 | 726 | 0.0001 | 0.9999 | 78.18 |
| 34.5 | 11,601,395 | 156,250 | 0.0135 | 0.9865 | 78.18 |
| 35.5 | 11,445,145 | 0 | 0.0000 | 1.0000 | 77.13 |
| 36.5 | 11,445,145 | 120,175 | 0.0105 | 0.9895 | 77.13 |
| 37.5 | 11,324,970 | 5,501 | 0.0005 | 0.9995 | 76.32 |
| 38.5 | 11,319,469 | 22,140 | 0.0020 | 0.9980 | 76.28 |

DUKE ENERGY PROGRESS

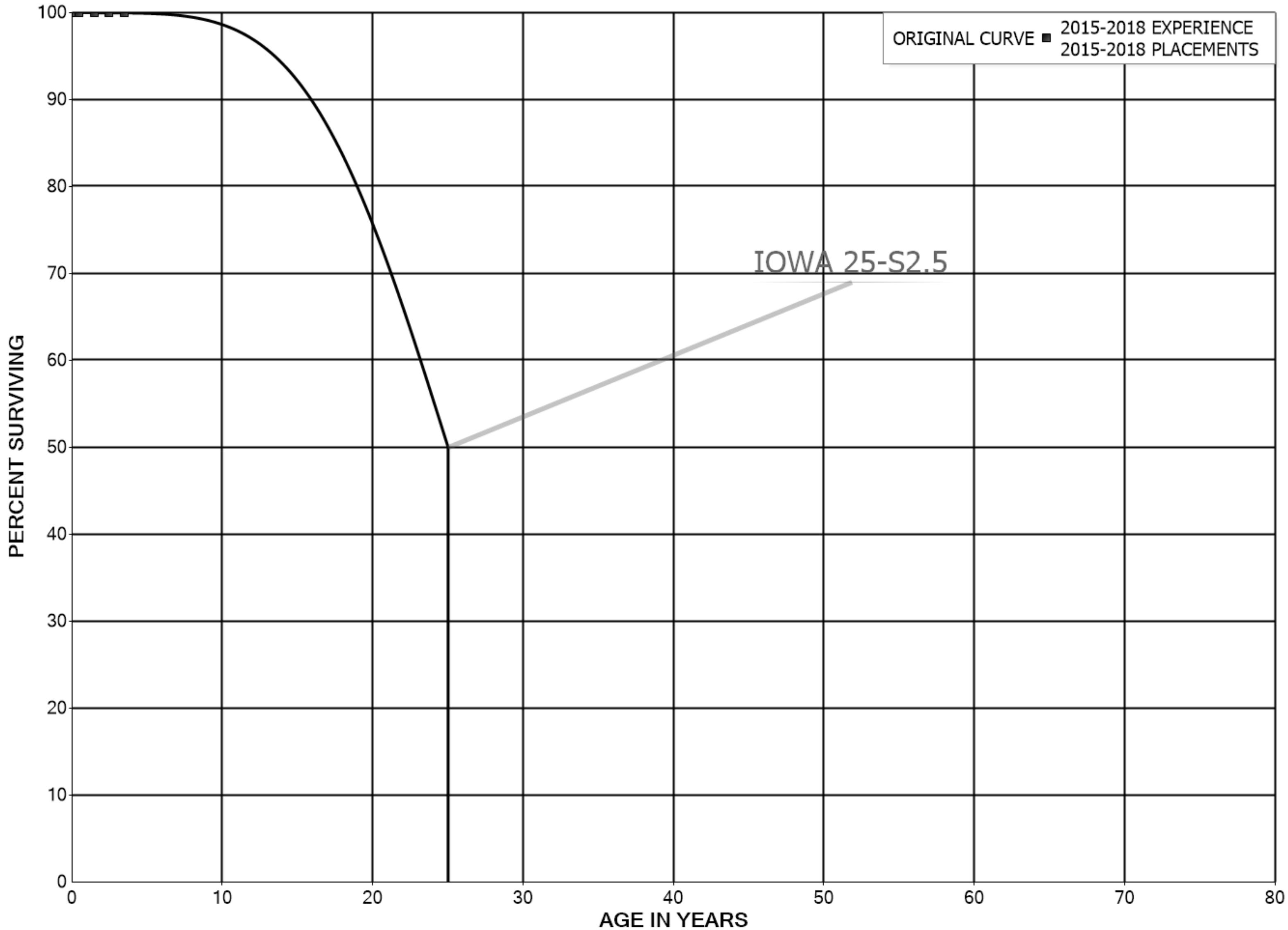
ACCOUNT 344 GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 11,297,329 | 314,478 | 0.0278 | 0.9722 | 76.13 |
| 40.5 | 10,982,850 | 299,852 | 0.0273 | 0.9727 | 74.01 |
| 41.5 | 9,803,203 | 57,202 | 0.0058 | 0.9942 | 71.99 |
| 42.5 | 9,746,000 | 266,319 | 0.0273 | 0.9727 | 71.57 |
| 43.5 | 9,155,944 | 580,846 | 0.0634 | 0.9366 | 69.61 |
| 44.5 | 5,266,618 | | 0.0000 | 1.0000 | 65.20 |
| 45.5 | 3,816,133 | | 0.0000 | 1.0000 | 65.20 |
| 46.5 | 3,816,133 | | 0.0000 | 1.0000 | 65.20 |
| 47.5 | 2,143,130 | | 0.0000 | 1.0000 | 65.20 |
| 48.5 | 297,494 | | 0.0000 | 1.0000 | 65.20 |
| 49.5 | | | | | 65.20 |

DUKE ENERGY PROGRESS
ACCOUNT 344.2 GENERATORS - SOLAR
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

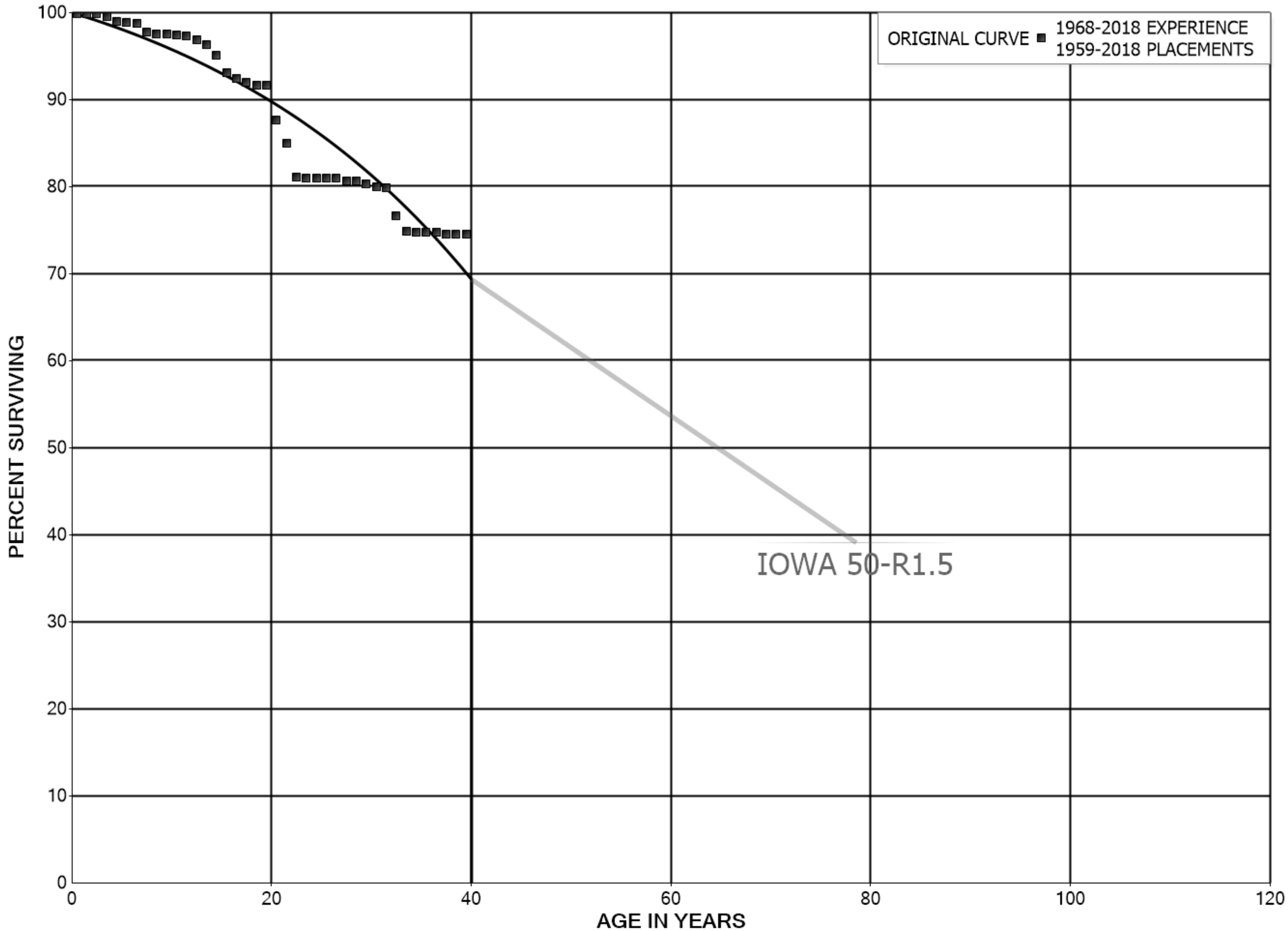
ACCOUNT 344.2 GENERATORS - SOLAR

ORIGINAL LIFE TABLE

PLACEMENT BAND 2015-2018 EXPERIENCE BAND 2015-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 187,470,961 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 178,745,731 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 178,745,731 | | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 129,290,091 | | 0.0000 | 1.0000 | 100.00 |
| 3.5 | | | | | 100.00 |

DUKE ENERGY PROGRESS
ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 329,696,842 | 493,243 | 0.0015 | 0.9985 | 100.00 |
| 0.5 | 327,289,152 | | 0.0000 | 1.0000 | 99.85 |
| 1.5 | 317,911,059 | 56,772 | 0.0002 | 0.9998 | 99.85 |
| 2.5 | 313,427,586 | 1,014,658 | 0.0032 | 0.9968 | 99.83 |
| 3.5 | 300,523,393 | 1,731,534 | 0.0058 | 0.9942 | 99.51 |
| 4.5 | 298,732,582 | 386,302 | 0.0013 | 0.9987 | 98.94 |
| 5.5 | 235,984,841 | 283,590 | 0.0012 | 0.9988 | 98.81 |
| 6.5 | 159,387,459 | 1,469,084 | 0.0092 | 0.9908 | 98.69 |
| 7.5 | 107,737,361 | 293,205 | 0.0027 | 0.9973 | 97.78 |
| 8.5 | 105,133,601 | 49,594 | 0.0005 | 0.9995 | 97.51 |
| 9.5 | 94,204,035 | 116,593 | 0.0012 | 0.9988 | 97.47 |
| 10.5 | 93,066,957 | 32,036 | 0.0003 | 0.9997 | 97.35 |
| 11.5 | 92,391,065 | 479,392 | 0.0052 | 0.9948 | 97.31 |
| 12.5 | 91,691,145 | 493,229 | 0.0054 | 0.9946 | 96.81 |
| 13.5 | 91,216,980 | 1,111,913 | 0.0122 | 0.9878 | 96.29 |
| 14.5 | 89,971,482 | 1,923,332 | 0.0214 | 0.9786 | 95.11 |
| 15.5 | 87,889,485 | 623,031 | 0.0071 | 0.9929 | 93.08 |
| 16.5 | 66,693,973 | 376,506 | 0.0056 | 0.9944 | 92.42 |
| 17.5 | 43,491,944 | 130,717 | 0.0030 | 0.9970 | 91.90 |
| 18.5 | 18,859,129 | 4,160 | 0.0002 | 0.9998 | 91.62 |
| 19.5 | 17,188,576 | 745,401 | 0.0434 | 0.9566 | 91.60 |
| 20.5 | 13,534,254 | 404,797 | 0.0299 | 0.9701 | 87.63 |
| 21.5 | 12,567,718 | 586,337 | 0.0467 | 0.9533 | 85.01 |
| 22.5 | 7,059,434 | 6,389 | 0.0009 | 0.9991 | 81.04 |
| 23.5 | 7,021,350 | 5,948 | 0.0008 | 0.9992 | 80.97 |
| 24.5 | 5,082,653 | | 0.0000 | 1.0000 | 80.90 |
| 25.5 | 4,998,498 | | 0.0000 | 1.0000 | 80.90 |
| 26.5 | 4,947,778 | 16,529 | 0.0033 | 0.9967 | 80.90 |
| 27.5 | 4,913,173 | 1,706 | 0.0003 | 0.9997 | 80.63 |
| 28.5 | 4,870,647 | 17,606 | 0.0036 | 0.9964 | 80.60 |
| 29.5 | 4,388,861 | 19,845 | 0.0045 | 0.9955 | 80.31 |
| 30.5 | 4,350,169 | 4,634 | 0.0011 | 0.9989 | 79.95 |
| 31.5 | 4,328,349 | 173,383 | 0.0401 | 0.9599 | 79.86 |
| 32.5 | 4,153,346 | 97,973 | 0.0236 | 0.9764 | 76.66 |
| 33.5 | 4,055,373 | 5,513 | 0.0014 | 0.9986 | 74.86 |
| 34.5 | 3,967,169 | 3,856 | 0.0010 | 0.9990 | 74.75 |
| 35.5 | 3,963,313 | 56 | 0.0000 | 1.0000 | 74.68 |
| 36.5 | 3,957,331 | 7,406 | 0.0019 | 0.9981 | 74.68 |
| 37.5 | 3,919,382 | | 0.0000 | 1.0000 | 74.54 |
| 38.5 | 3,919,382 | 1,710 | 0.0004 | 0.9996 | 74.54 |

DUKE ENERGY PROGRESS

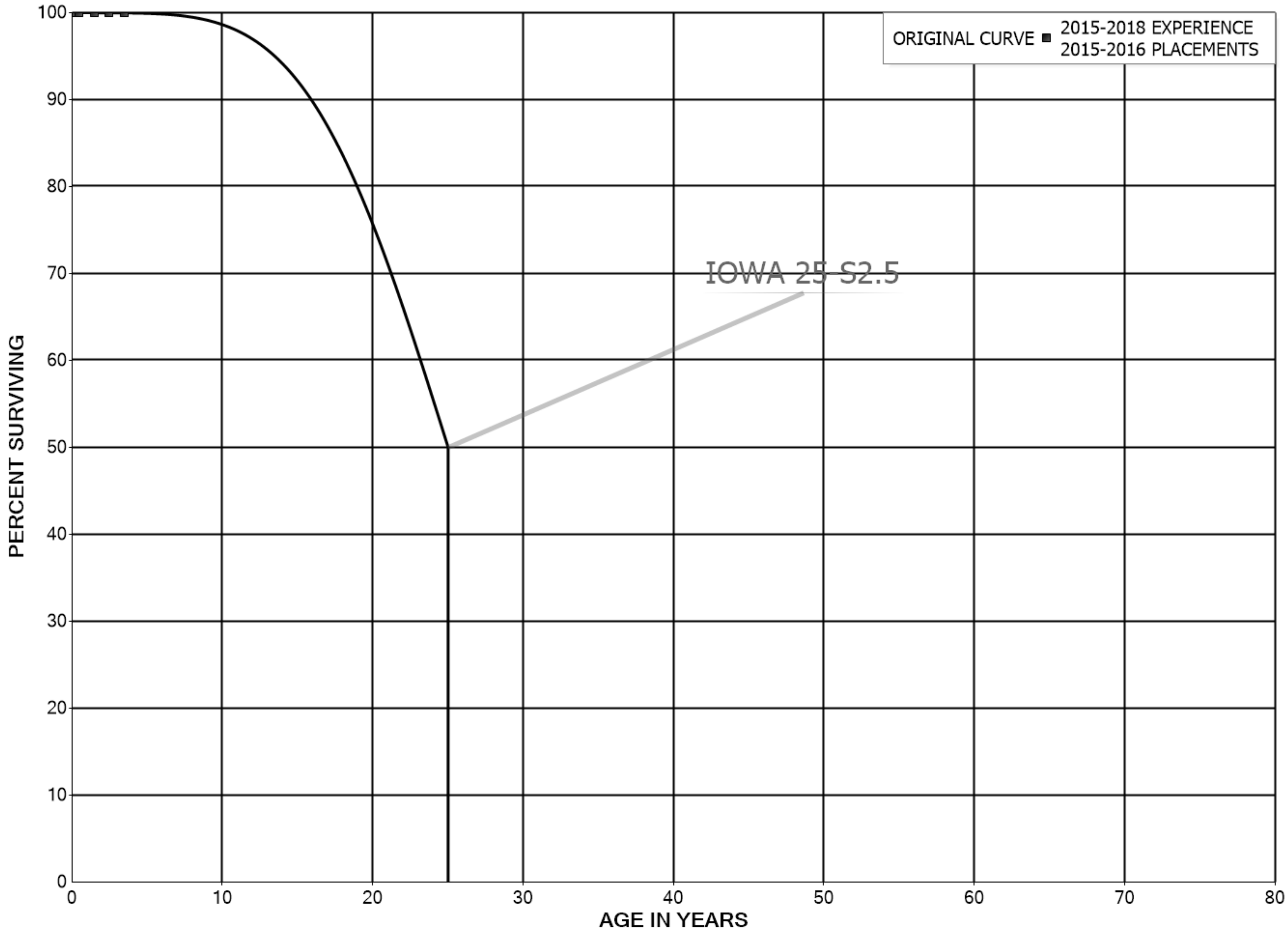
ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 3,912,967 | 85,567 | 0.0219 | 0.9781 | 74.51 |
| 40.5 | 3,827,400 | 52,861 | 0.0138 | 0.9862 | 72.88 |
| 41.5 | 2,842,558 | 119,398 | 0.0420 | 0.9580 | 71.87 |
| 42.5 | 2,723,160 | 110,246 | 0.0405 | 0.9595 | 68.85 |
| 43.5 | 2,591,873 | 80,862 | 0.0312 | 0.9688 | 66.07 |
| 44.5 | 2,003,722 | | 0.0000 | 1.0000 | 64.00 |
| 45.5 | 1,935,276 | | 0.0000 | 1.0000 | 64.00 |
| 46.5 | 1,935,276 | 14,997 | 0.0077 | 0.9923 | 64.00 |
| 47.5 | 692,568 | 14,491 | 0.0209 | 0.9791 | 63.51 |
| 48.5 | 84,807 | | 0.0000 | 1.0000 | 62.18 |
| 49.5 | | | | | 62.18 |

DUKE ENERGY PROGRESS
ACCOUNT 345.2 ACCESSORY ELECTRIC EQUIPMENT - SOLAR
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

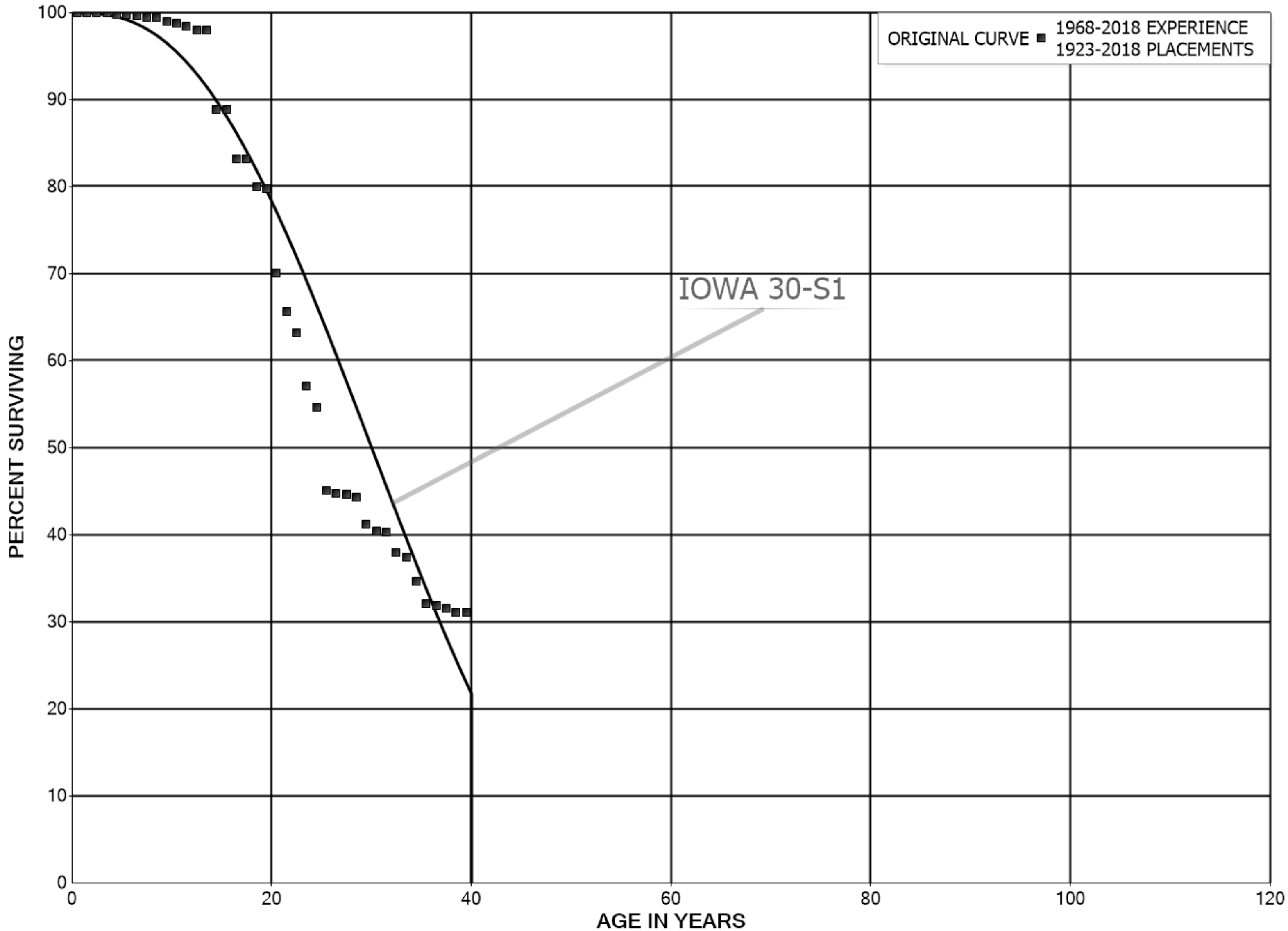
ACCOUNT 345.2 ACCESSORY ELECTRIC EQUIPMENT - SOLAR

ORIGINAL LIFE TABLE

PLACEMENT BAND 2015-2016 EXPERIENCE BAND 2015-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 4,686,715 | | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 4,686,715 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 4,686,715 | | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 4,047,631 | | 0.0000 | 1.0000 | 100.00 |
| 3.5 | | | | | 100.00 |

DUKE ENERGY PROGRESS
ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 53,088,279 | 614 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 51,633,723 | | 0.0000 | 1.0000 | 100.00 |
| 1.5 | 45,733,465 | 38 | 0.0000 | 1.0000 | 100.00 |
| 2.5 | 40,723,448 | 591 | 0.0000 | 1.0000 | 100.00 |
| 3.5 | 39,429,242 | 89,287 | 0.0023 | 0.9977 | 100.00 |
| 4.5 | 38,561,755 | 15,854 | 0.0004 | 0.9996 | 99.77 |
| 5.5 | 31,480,991 | 23,306 | 0.0007 | 0.9993 | 99.73 |
| 6.5 | 22,814,457 | 60,514 | 0.0027 | 0.9973 | 99.66 |
| 7.5 | 14,577,126 | 400 | 0.0000 | 1.0000 | 99.39 |
| 8.5 | 12,811,390 | 63,438 | 0.0050 | 0.9950 | 99.39 |
| 9.5 | 11,083,255 | 19,513 | 0.0018 | 0.9982 | 98.90 |
| 10.5 | 10,887,769 | 38,924 | 0.0036 | 0.9964 | 98.72 |
| 11.5 | 10,571,357 | 47,295 | 0.0045 | 0.9955 | 98.37 |
| 12.5 | 10,310,106 | 430 | 0.0000 | 1.0000 | 97.93 |
| 13.5 | 10,460,840 | 971,007 | 0.0928 | 0.9072 | 97.93 |
| 14.5 | 9,411,537 | 1,931 | 0.0002 | 0.9998 | 88.84 |
| 15.5 | 8,897,167 | 561,201 | 0.0631 | 0.9369 | 88.82 |
| 16.5 | 6,014,258 | 589 | 0.0001 | 0.9999 | 83.22 |
| 17.5 | 4,170,020 | 160,855 | 0.0386 | 0.9614 | 83.21 |
| 18.5 | 1,395,398 | 4,019 | 0.0029 | 0.9971 | 80.00 |
| 19.5 | 1,440,737 | 174,952 | 0.1214 | 0.8786 | 79.77 |
| 20.5 | 1,160,986 | 74,349 | 0.0640 | 0.9360 | 70.08 |
| 21.5 | 1,102,341 | 40,296 | 0.0366 | 0.9634 | 65.59 |
| 22.5 | 1,051,642 | 102,130 | 0.0971 | 0.9029 | 63.20 |
| 23.5 | 957,941 | 41,198 | 0.0430 | 0.9570 | 57.06 |
| 24.5 | 840,353 | 146,840 | 0.1747 | 0.8253 | 54.60 |
| 25.5 | 711,539 | 5,297 | 0.0074 | 0.9926 | 45.06 |
| 26.5 | 696,233 | 1,657 | 0.0024 | 0.9976 | 44.73 |
| 27.5 | 711,968 | 5,978 | 0.0084 | 0.9916 | 44.62 |
| 28.5 | 720,934 | 49,922 | 0.0692 | 0.9308 | 44.25 |
| 29.5 | 658,775 | 12,227 | 0.0186 | 0.9814 | 41.18 |
| 30.5 | 635,263 | 1,512 | 0.0024 | 0.9976 | 40.42 |
| 31.5 | 659,253 | 37,859 | 0.0574 | 0.9426 | 40.32 |
| 32.5 | 598,409 | 8,989 | 0.0150 | 0.9850 | 38.01 |
| 33.5 | 608,885 | 45,273 | 0.0744 | 0.9256 | 37.44 |
| 34.5 | 549,406 | 40,186 | 0.0731 | 0.9269 | 34.65 |
| 35.5 | 503,996 | 3,891 | 0.0077 | 0.9923 | 32.12 |
| 36.5 | 500,111 | 5,551 | 0.0111 | 0.9889 | 31.87 |
| 37.5 | 491,521 | 6,472 | 0.0132 | 0.9868 | 31.52 |
| 38.5 | 485,081 | | 0.0000 | 1.0000 | 31.10 |

DUKE ENERGY PROGRESS

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 487,159 | 2,530 | 0.0052 | 0.9948 | 31.10 |
| 40.5 | 480,634 | 392,316 | 0.8162 | 0.1838 | 30.94 |
| 41.5 | 81,454 | 38,593 | 0.4738 | 0.5262 | 5.69 |
| 42.5 | 43,043 | 2,882 | 0.0669 | 0.9331 | 2.99 |
| 43.5 | 39,979 | 758 | 0.0190 | 0.9810 | 2.79 |
| 44.5 | 26,822 | 10,235 | 0.3816 | 0.6184 | 2.74 |
| 45.5 | 14,091 | 7,317 | 0.5193 | 0.4807 | 1.69 |
| 46.5 | 6,774 | 4,000 | 0.5905 | 0.4095 | 0.81 |
| 47.5 | 2,774 | 2,468 | 0.8896 | 0.1104 | 0.33 |
| 48.5 | 306 | 306 | 1.0000 | | 0.04 |
| 49.5 | | | | | |
| 50.5 | | | | | |
| 51.5 | | | | | |
| 52.5 | | | | | |
| 53.5 | | | | | |
| 54.5 | | | | | |
| 55.5 | | | | | |
| 56.5 | | | | | |
| 57.5 | | | | | |
| 58.5 | | | | | |
| 59.5 | | | | | |
| 60.5 | | | | | |
| 61.5 | | | | | |
| 62.5 | | | | | |
| 63.5 | | | | | |
| 64.5 | | | | | |
| 65.5 | | | | | |
| 66.5 | | | | | |
| 67.5 | | | | | |
| 68.5 | | | | | |
| 69.5 | | | | | |
| 70.5 | | | | | |
| 71.5 | | | | | |
| 72.5 | | | | | |
| 73.5 | | | | | |
| 74.5 | | | | | |
| 75.5 | | | | | |
| 76.5 | | | | | |
| 77.5 | | | | | |
| 78.5 | | | | | |

DUKE ENERGY PROGRESS

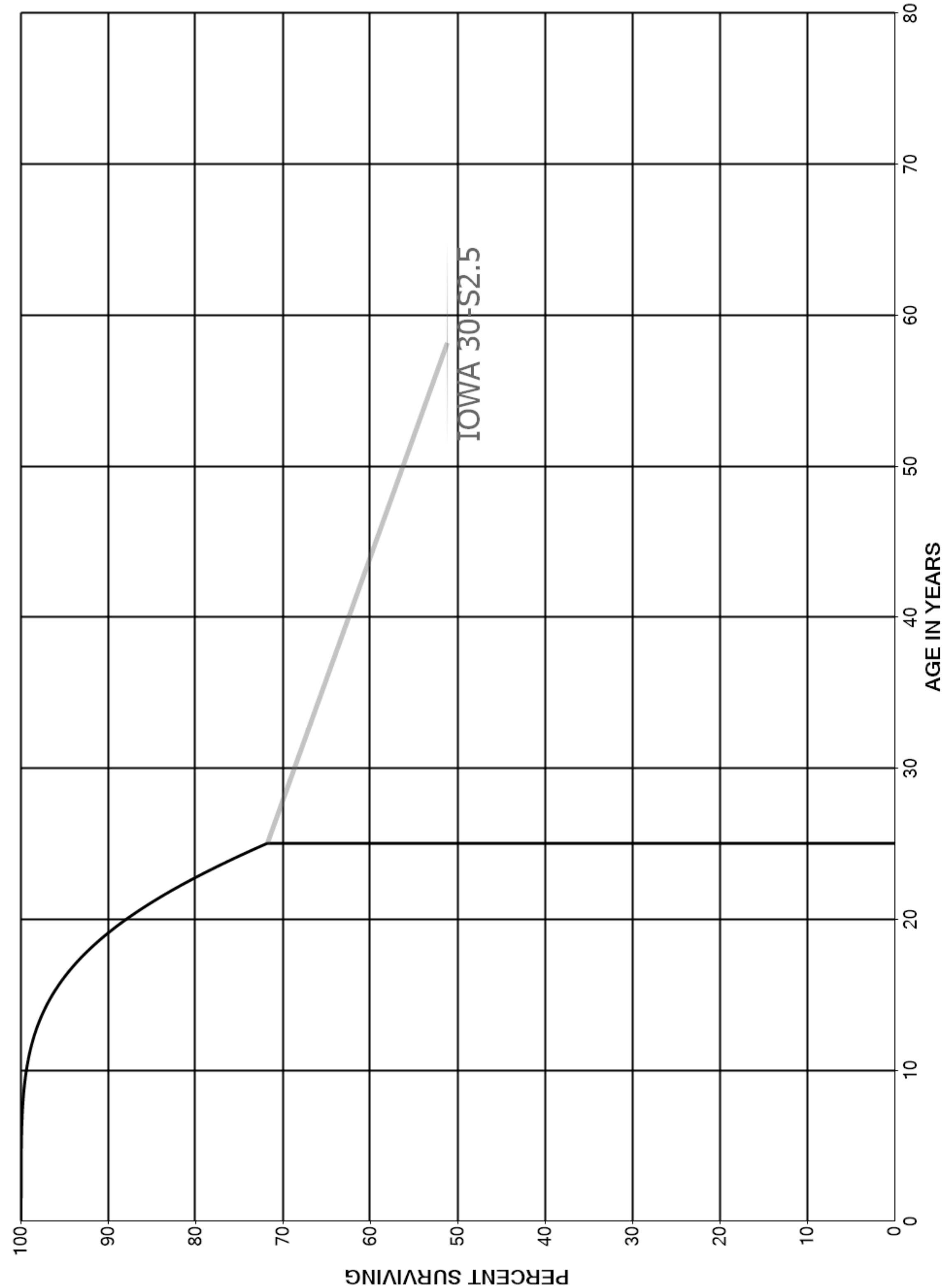
ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

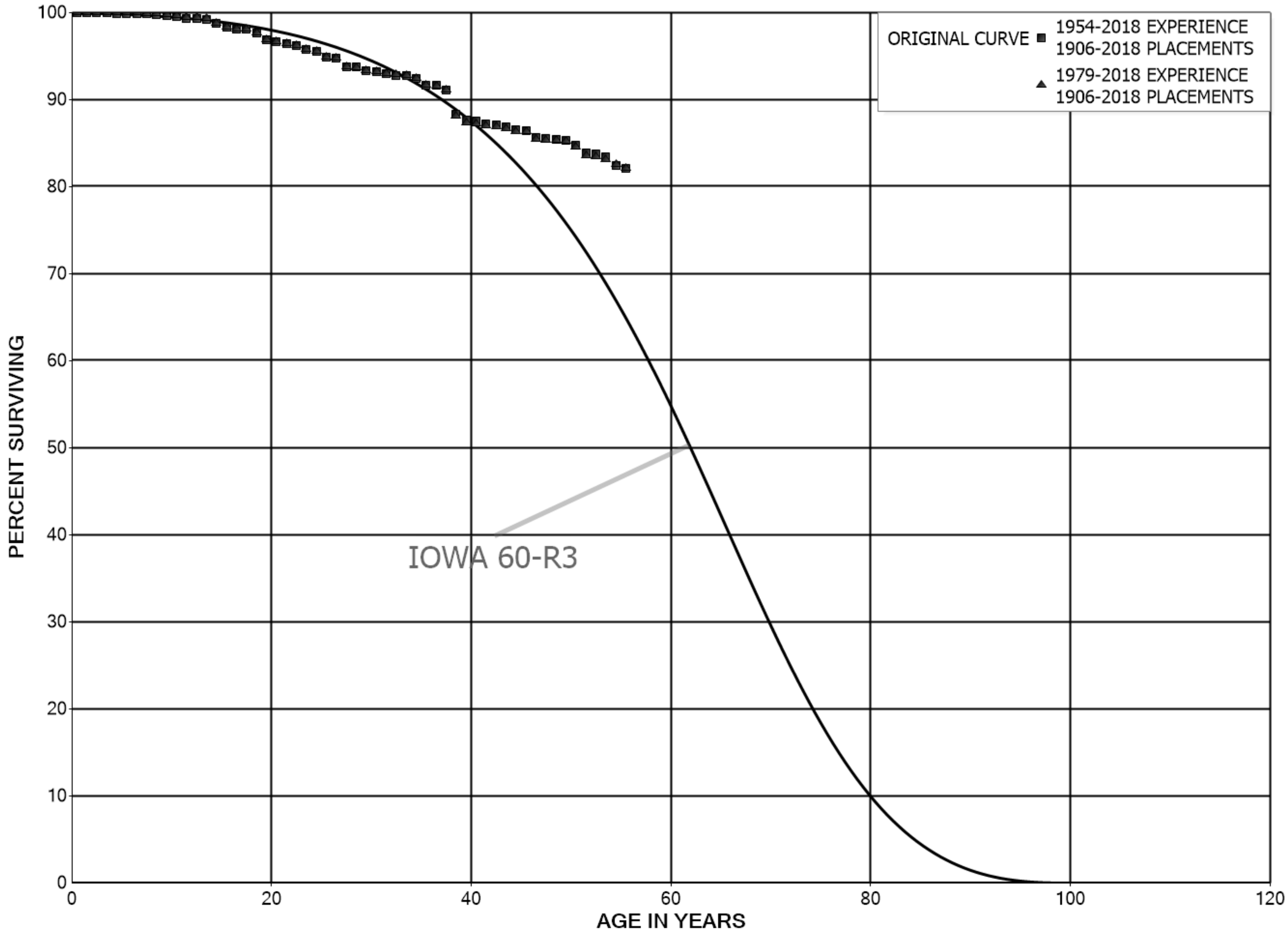
PLACEMENT BAND 1923-2018 EXPERIENCE BAND 1968-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | | | | | |
| 80.5 | | | | | |
| 81.5 | | | | | |
| 82.5 | | | | | |
| 83.5 | | | | | |
| 84.5 | | | | | |
| 85.5 | | | | | |
| 86.5 | | | | | |
| 87.5 | | | | | |
| 88.5 | | | | | |
| 89.5 | 4,590 | | 0.0000 | | |
| 90.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 346.2 MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR
SMOOTH SURVIVOR CURVE



DUKE ENERGY PROGRESS
ACCOUNT 352 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 100,121,997 | 48,053 | 0.0005 | 0.9995 | 100.00 |
| 0.5 | 88,783,130 | 4,816 | 0.0001 | 0.9999 | 99.95 |
| 1.5 | 85,928,703 | 10,469 | 0.0001 | 0.9999 | 99.95 |
| 2.5 | 85,328,716 | 12,748 | 0.0001 | 0.9999 | 99.93 |
| 3.5 | 75,314,142 | 30,420 | 0.0004 | 0.9996 | 99.92 |
| 4.5 | 75,310,773 | 4,565 | 0.0001 | 0.9999 | 99.88 |
| 5.5 | 75,826,738 | 4,422 | 0.0001 | 0.9999 | 99.87 |
| 6.5 | 74,489,686 | 54,770 | 0.0007 | 0.9993 | 99.87 |
| 7.5 | 71,864,527 | 22,997 | 0.0003 | 0.9997 | 99.79 |
| 8.5 | 71,579,390 | 71,084 | 0.0010 | 0.9990 | 99.76 |
| 9.5 | 61,115,735 | 83,200 | 0.0014 | 0.9986 | 99.66 |
| 10.5 | 60,418,600 | 114,345 | 0.0019 | 0.9981 | 99.53 |
| 11.5 | 58,996,279 | 23,785 | 0.0004 | 0.9996 | 99.34 |
| 12.5 | 59,144,056 | 55,588 | 0.0009 | 0.9991 | 99.30 |
| 13.5 | 57,891,466 | 292,345 | 0.0050 | 0.9950 | 99.21 |
| 14.5 | 53,965,853 | 231,286 | 0.0043 | 0.9957 | 98.70 |
| 15.5 | 52,519,753 | 110,160 | 0.0021 | 0.9979 | 98.28 |
| 16.5 | 50,334,210 | 17,500 | 0.0003 | 0.9997 | 98.08 |
| 17.5 | 48,346,043 | 228,382 | 0.0047 | 0.9953 | 98.04 |
| 18.5 | 44,391,252 | 354,463 | 0.0080 | 0.9920 | 97.58 |
| 19.5 | 41,440,614 | 66,537 | 0.0016 | 0.9984 | 96.80 |
| 20.5 | 40,666,460 | 95,356 | 0.0023 | 0.9977 | 96.64 |
| 21.5 | 39,325,701 | 96,973 | 0.0025 | 0.9975 | 96.42 |
| 22.5 | 35,961,557 | 167,174 | 0.0046 | 0.9954 | 96.18 |
| 23.5 | 32,706,204 | 68,922 | 0.0021 | 0.9979 | 95.73 |
| 24.5 | 32,057,795 | 237,364 | 0.0074 | 0.9926 | 95.53 |
| 25.5 | 30,336,504 | 40,653 | 0.0013 | 0.9987 | 94.82 |
| 26.5 | 29,339,979 | 291,745 | 0.0099 | 0.9901 | 94.70 |
| 27.5 | 28,562,000 | 23,587 | 0.0008 | 0.9992 | 93.75 |
| 28.5 | 27,285,783 | 120,183 | 0.0044 | 0.9956 | 93.68 |
| 29.5 | 22,064,007 | 23,009 | 0.0010 | 0.9990 | 93.26 |
| 30.5 | 20,518,391 | 38,716 | 0.0019 | 0.9981 | 93.17 |
| 31.5 | 18,129,394 | 42,404 | 0.0023 | 0.9977 | 92.99 |
| 32.5 | 17,484,916 | 11,874 | 0.0007 | 0.9993 | 92.77 |
| 33.5 | 16,664,729 | 55,296 | 0.0033 | 0.9967 | 92.71 |
| 34.5 | 15,856,664 | 131,686 | 0.0083 | 0.9917 | 92.40 |
| 35.5 | 11,777,400 | 8,981 | 0.0008 | 0.9992 | 91.64 |
| 36.5 | 10,513,184 | 51,628 | 0.0049 | 0.9951 | 91.57 |
| 37.5 | 9,608,110 | 301,097 | 0.0313 | 0.9687 | 91.12 |
| 38.5 | 8,979,618 | 70,220 | 0.0078 | 0.9922 | 88.26 |

DUKE ENERGY PROGRESS

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 6,581,103 | 8,358 | 0.0013 | 0.9987 | 87.57 |
| 40.5 | 5,513,335 | 18,733 | 0.0034 | 0.9966 | 87.46 |
| 41.5 | 4,757,583 | 7,169 | 0.0015 | 0.9985 | 87.16 |
| 42.5 | 4,249,545 | 11,171 | 0.0026 | 0.9974 | 87.03 |
| 43.5 | 3,879,884 | 12,410 | 0.0032 | 0.9968 | 86.80 |
| 44.5 | 2,639,133 | 2,696 | 0.0010 | 0.9990 | 86.52 |
| 45.5 | 2,357,193 | 20,917 | 0.0089 | 0.9911 | 86.44 |
| 46.5 | 1,874,867 | 3,929 | 0.0021 | 0.9979 | 85.67 |
| 47.5 | 1,660,635 | 1,185 | 0.0007 | 0.9993 | 85.49 |
| 48.5 | 1,638,714 | 2,136 | 0.0013 | 0.9987 | 85.43 |
| 49.5 | 1,625,305 | 10,303 | 0.0063 | 0.9937 | 85.32 |
| 50.5 | 1,439,931 | 16,438 | 0.0114 | 0.9886 | 84.78 |
| 51.5 | 1,298,049 | 1,008 | 0.0008 | 0.9992 | 83.81 |
| 52.5 | 1,209,031 | 4,781 | 0.0040 | 0.9960 | 83.74 |
| 53.5 | 1,158,192 | 13,514 | 0.0117 | 0.9883 | 83.41 |
| 54.5 | 1,121,614 | 5,560 | 0.0050 | 0.9950 | 82.44 |
| 55.5 | 1,098,756 | 3,877 | 0.0035 | 0.9965 | 82.03 |
| 56.5 | 1,086,532 | 47 | 0.0000 | 1.0000 | 81.74 |
| 57.5 | 1,080,798 | 496 | 0.0005 | 0.9995 | 81.74 |
| 58.5 | 1,075,193 | 2,252 | 0.0021 | 0.9979 | 81.70 |
| 59.5 | 1,072,352 | 711 | 0.0007 | 0.9993 | 81.53 |
| 60.5 | 1,055,648 | 881 | 0.0008 | 0.9992 | 81.47 |
| 61.5 | 1,027,646 | 5,363 | 0.0052 | 0.9948 | 81.41 |
| 62.5 | 996,586 | 35 | 0.0000 | 1.0000 | 80.98 |
| 63.5 | 992,960 | 18,249 | 0.0184 | 0.9816 | 80.98 |
| 64.5 | 962,356 | 3,121 | 0.0032 | 0.9968 | 79.49 |
| 65.5 | 943,154 | 914 | 0.0010 | 0.9990 | 79.23 |
| 66.5 | 914,674 | 212 | 0.0002 | 0.9998 | 79.16 |
| 67.5 | 911,176 | 247 | 0.0003 | 0.9997 | 79.14 |
| 68.5 | 890,000 | 3,380 | 0.0038 | 0.9962 | 79.12 |
| 69.5 | 786,918 | 61 | 0.0001 | 0.9999 | 78.82 |
| 70.5 | 783,961 | 2,218 | 0.0028 | 0.9972 | 78.81 |
| 71.5 | 606,551 | 1,957 | 0.0032 | 0.9968 | 78.59 |
| 72.5 | 600,125 | 111 | 0.0002 | 0.9998 | 78.33 |
| 73.5 | 598,197 | 1,257 | 0.0021 | 0.9979 | 78.32 |
| 74.5 | 596,940 | 2,315 | 0.0039 | 0.9961 | 78.15 |
| 75.5 | 594,625 | 1,648 | 0.0028 | 0.9972 | 77.85 |
| 76.5 | 592,435 | 417 | 0.0007 | 0.9993 | 77.64 |
| 77.5 | 567,329 | 1,885 | 0.0033 | 0.9967 | 77.58 |
| 78.5 | 565,404 | 1 | 0.0000 | 1.0000 | 77.32 |

DUKE ENERGY PROGRESS

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 565,403 | 462 | 0.0008 | 0.9992 | 77.32 |
| 80.5 | 556,219 | 1,123 | 0.0020 | 0.9980 | 77.26 |
| 81.5 | 505,888 | 36,119 | 0.0714 | 0.9286 | 77.10 |
| 82.5 | 263,661 | 56 | 0.0002 | 0.9998 | 71.60 |
| 83.5 | 263,605 | 546 | 0.0021 | 0.9979 | 71.58 |
| 84.5 | 263,059 | | 0.0000 | 1.0000 | 71.44 |
| 85.5 | 263,059 | 97 | 0.0004 | 0.9996 | 71.44 |
| 86.5 | 262,962 | 176 | 0.0007 | 0.9993 | 71.41 |
| 87.5 | 256,338 | 767 | 0.0030 | 0.9970 | 71.36 |
| 88.5 | 228,772 | | 0.0000 | 1.0000 | 71.15 |
| 89.5 | 228,772 | 2,350 | 0.0103 | 0.9897 | 71.15 |
| 90.5 | 151,589 | 1,422 | 0.0094 | 0.9906 | 70.42 |
| 91.5 | 107,114 | 77 | 0.0007 | 0.9993 | 69.76 |
| 92.5 | 104,805 | 1,544 | 0.0147 | 0.9853 | 69.71 |
| 93.5 | 60,490 | 782 | 0.0129 | 0.9871 | 68.68 |
| 94.5 | 38,962 | 1,483 | 0.0381 | 0.9619 | 67.79 |
| 95.5 | | | | | 65.21 |

DUKE ENERGY PROGRESS

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 94,404,089 | 1,431 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 84,246,336 | 4,816 | 0.0001 | 0.9999 | 100.00 |
| 1.5 | 82,387,130 | 10,469 | 0.0001 | 0.9999 | 99.99 |
| 2.5 | 82,204,464 | 12,637 | 0.0002 | 0.9998 | 99.98 |
| 3.5 | 72,685,062 | 25,290 | 0.0003 | 0.9997 | 99.96 |
| 4.5 | 73,282,785 | 3,991 | 0.0001 | 0.9999 | 99.93 |
| 5.5 | 74,167,061 | 4,217 | 0.0001 | 0.9999 | 99.92 |
| 6.5 | 72,999,986 | 53,605 | 0.0007 | 0.9993 | 99.92 |
| 7.5 | 70,641,660 | 19,121 | 0.0003 | 0.9997 | 99.85 |
| 8.5 | 70,376,616 | 70,579 | 0.0010 | 0.9990 | 99.82 |
| 9.5 | 59,932,817 | 82,639 | 0.0014 | 0.9986 | 99.72 |
| 10.5 | 59,421,195 | 113,085 | 0.0019 | 0.9981 | 99.58 |
| 11.5 | 58,142,083 | 21,547 | 0.0004 | 0.9996 | 99.39 |
| 12.5 | 58,363,951 | 55,168 | 0.0009 | 0.9991 | 99.35 |
| 13.5 | 57,176,326 | 292,345 | 0.0051 | 0.9949 | 99.26 |
| 14.5 | 53,281,633 | 231,000 | 0.0043 | 0.9957 | 98.75 |
| 15.5 | 51,844,451 | 110,160 | 0.0021 | 0.9979 | 98.32 |
| 16.5 | 49,610,657 | 17,500 | 0.0004 | 0.9996 | 98.12 |
| 17.5 | 47,387,750 | 228,056 | 0.0048 | 0.9952 | 98.08 |
| 18.5 | 43,436,941 | 354,263 | 0.0082 | 0.9918 | 97.61 |
| 19.5 | 40,579,118 | 64,135 | 0.0016 | 0.9984 | 96.81 |
| 20.5 | 39,824,769 | 93,082 | 0.0023 | 0.9977 | 96.66 |
| 21.5 | 38,514,476 | 95,317 | 0.0025 | 0.9975 | 96.43 |
| 22.5 | 35,170,591 | 167,174 | 0.0048 | 0.9952 | 96.20 |
| 23.5 | 31,877,716 | 68,920 | 0.0022 | 0.9978 | 95.74 |
| 24.5 | 31,228,643 | 236,961 | 0.0076 | 0.9924 | 95.53 |
| 25.5 | 29,449,315 | 40,494 | 0.0014 | 0.9986 | 94.81 |
| 26.5 | 28,472,256 | 291,745 | 0.0102 | 0.9898 | 94.68 |
| 27.5 | 27,696,846 | 23,587 | 0.0009 | 0.9991 | 93.71 |
| 28.5 | 26,397,728 | 105,248 | 0.0040 | 0.9960 | 93.63 |
| 29.5 | 21,278,686 | 22,949 | 0.0011 | 0.9989 | 93.25 |
| 30.5 | 19,695,997 | 38,716 | 0.0020 | 0.9980 | 93.15 |
| 31.5 | 17,485,161 | 35,154 | 0.0020 | 0.9980 | 92.97 |
| 32.5 | 16,853,249 | 8,415 | 0.0005 | 0.9995 | 92.78 |
| 33.5 | 16,038,191 | 55,296 | 0.0034 | 0.9966 | 92.74 |
| 34.5 | 15,230,124 | 131,586 | 0.0086 | 0.9914 | 92.42 |
| 35.5 | 11,152,413 | 8,981 | 0.0008 | 0.9992 | 91.62 |
| 36.5 | 9,889,423 | 51,528 | 0.0052 | 0.9948 | 91.54 |
| 37.5 | 9,014,626 | 300,822 | 0.0334 | 0.9666 | 91.07 |
| 38.5 | 8,386,452 | 66,222 | 0.0079 | 0.9921 | 88.03 |

DUKE ENERGY PROGRESS

ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 5,991,935 | 8,358 | 0.0014 | 0.9986 | 87.33 |
| 40.5 | 4,924,447 | 13,169 | 0.0027 | 0.9973 | 87.21 |
| 41.5 | 4,225,475 | 5,285 | 0.0013 | 0.9987 | 86.98 |
| 42.5 | 3,961,727 | 10,923 | 0.0028 | 0.9972 | 86.87 |
| 43.5 | 3,592,315 | 12,410 | 0.0035 | 0.9965 | 86.63 |
| 44.5 | 2,351,563 | 1,996 | 0.0008 | 0.9992 | 86.33 |
| 45.5 | 2,063,856 | 20,867 | 0.0101 | 0.9899 | 86.26 |
| 46.5 | 1,581,583 | 890 | 0.0006 | 0.9994 | 85.39 |
| 47.5 | 1,378,829 | 1,185 | 0.0009 | 0.9991 | 85.34 |
| 48.5 | 1,387,101 | 1,960 | 0.0014 | 0.9986 | 85.26 |
| 49.5 | 1,373,894 | 9,808 | 0.0071 | 0.9929 | 85.14 |
| 50.5 | 1,269,288 | 15,838 | 0.0125 | 0.9875 | 84.54 |
| 51.5 | 1,173,193 | 513 | 0.0004 | 0.9996 | 83.48 |
| 52.5 | 1,087,066 | 4,781 | 0.0044 | 0.9956 | 83.44 |
| 53.5 | 1,083,680 | 7,514 | 0.0069 | 0.9931 | 83.08 |
| 54.5 | 1,075,181 | 5,560 | 0.0052 | 0.9948 | 82.50 |
| 55.5 | 1,093,058 | 838 | 0.0008 | 0.9992 | 82.07 |
| 56.5 | 1,083,873 | 47 | 0.0000 | 1.0000 | 82.01 |
| 57.5 | 1,078,139 | 35 | 0.0000 | 1.0000 | 82.01 |
| 58.5 | 1,072,996 | 414 | 0.0004 | 0.9996 | 82.01 |
| 59.5 | 1,071,999 | 711 | 0.0007 | 0.9993 | 81.97 |
| 60.5 | 1,055,410 | 881 | 0.0008 | 0.9992 | 81.92 |
| 61.5 | 1,027,408 | 5,363 | 0.0052 | 0.9948 | 81.85 |
| 62.5 | 996,404 | 35 | 0.0000 | 1.0000 | 81.42 |
| 63.5 | 992,779 | 18,249 | 0.0184 | 0.9816 | 81.42 |
| 64.5 | 962,174 | 3,045 | 0.0032 | 0.9968 | 79.92 |
| 65.5 | 943,146 | 914 | 0.0010 | 0.9990 | 79.67 |
| 66.5 | 914,665 | 212 | 0.0002 | 0.9998 | 79.59 |
| 67.5 | 911,168 | 247 | 0.0003 | 0.9997 | 79.58 |
| 68.5 | 889,991 | 3,380 | 0.0038 | 0.9962 | 79.55 |
| 69.5 | 786,909 | 61 | 0.0001 | 0.9999 | 79.25 |
| 70.5 | 783,959 | 2,218 | 0.0028 | 0.9972 | 79.25 |
| 71.5 | 606,548 | 1,957 | 0.0032 | 0.9968 | 79.02 |
| 72.5 | 600,125 | 111 | 0.0002 | 0.9998 | 78.77 |
| 73.5 | 598,197 | 1,257 | 0.0021 | 0.9979 | 78.75 |
| 74.5 | 596,940 | 2,315 | 0.0039 | 0.9961 | 78.59 |
| 75.5 | 594,625 | 1,648 | 0.0028 | 0.9972 | 78.28 |
| 76.5 | 592,435 | 417 | 0.0007 | 0.9993 | 78.06 |
| 77.5 | 567,329 | 1,885 | 0.0033 | 0.9967 | 78.01 |
| 78.5 | 565,404 | 1 | 0.0000 | 1.0000 | 77.75 |

DUKE ENERGY PROGRESS

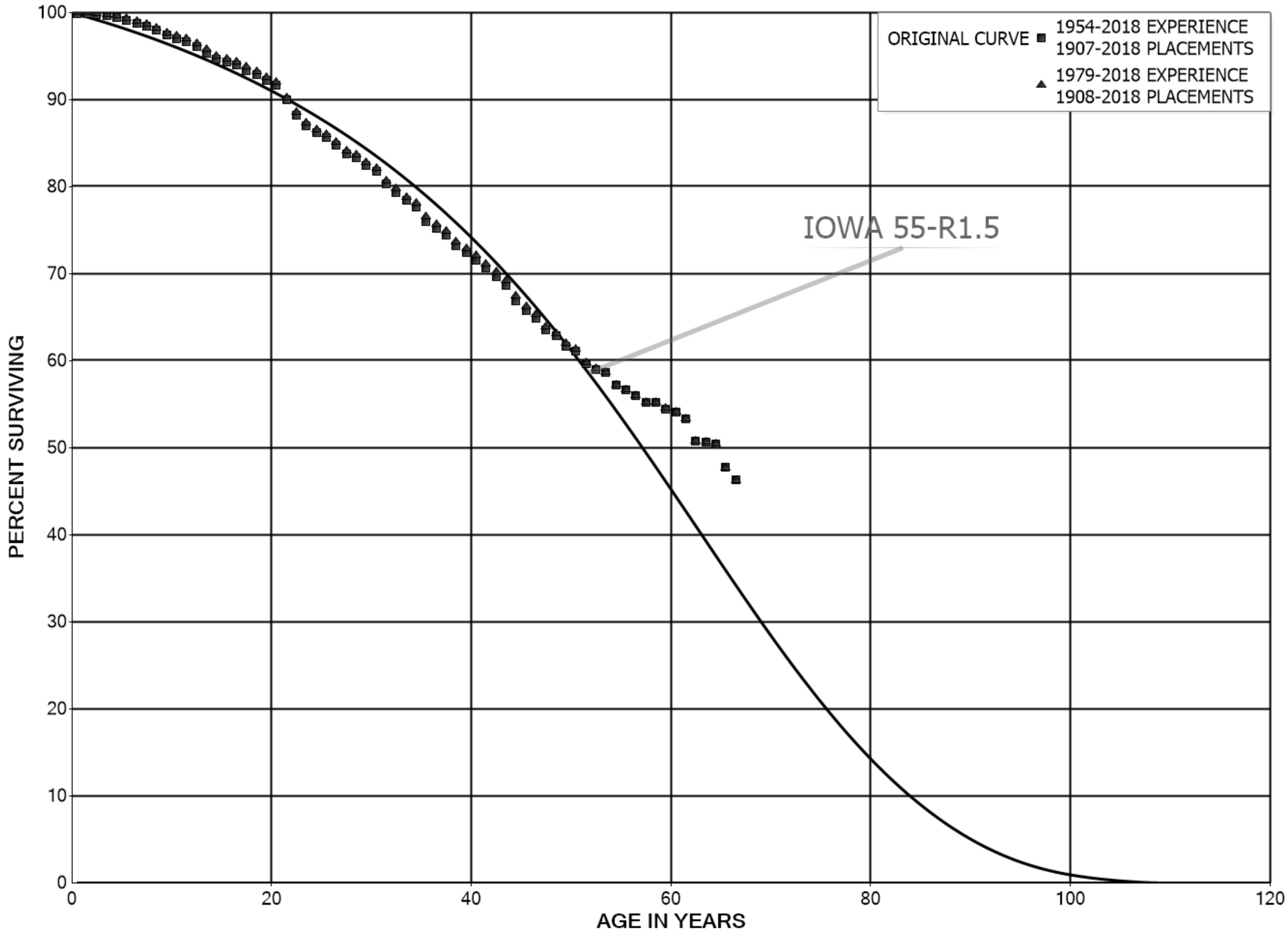
ACCOUNT 352 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 565,403 | 462 | 0.0008 | 0.9992 | 77.75 |
| 80.5 | 556,219 | 1,123 | 0.0020 | 0.9980 | 77.69 |
| 81.5 | 505,888 | 36,119 | 0.0714 | 0.9286 | 77.53 |
| 82.5 | 263,661 | 56 | 0.0002 | 0.9998 | 71.99 |
| 83.5 | 263,605 | 546 | 0.0021 | 0.9979 | 71.98 |
| 84.5 | 263,059 | | 0.0000 | 1.0000 | 71.83 |
| 85.5 | 263,059 | 97 | 0.0004 | 0.9996 | 71.83 |
| 86.5 | 262,962 | 176 | 0.0007 | 0.9993 | 71.80 |
| 87.5 | 256,338 | 767 | 0.0030 | 0.9970 | 71.76 |
| 88.5 | 228,772 | | 0.0000 | 1.0000 | 71.54 |
| 89.5 | 228,772 | 2,350 | 0.0103 | 0.9897 | 71.54 |
| 90.5 | 151,589 | 1,422 | 0.0094 | 0.9906 | 70.81 |
| 91.5 | 107,114 | 77 | 0.0007 | 0.9993 | 70.14 |
| 92.5 | 104,805 | 1,544 | 0.0147 | 0.9853 | 70.09 |
| 93.5 | 60,490 | 782 | 0.0129 | 0.9871 | 69.06 |
| 94.5 | 38,962 | 1,483 | 0.0381 | 0.9619 | 68.17 |
| 95.5 | | | | | 65.57 |

DUKE ENERGY PROGRESS
ACCOUNT 353 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1907-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,231,888,961 | 1,766,576 | 0.0014 | 0.9986 | 100.00 |
| 0.5 | 1,146,272,903 | 575,155 | 0.0005 | 0.9995 | 99.86 |
| 1.5 | 1,087,830,316 | 973,958 | 0.0009 | 0.9991 | 99.81 |
| 2.5 | 1,060,743,709 | 1,509,590 | 0.0014 | 0.9986 | 99.72 |
| 3.5 | 1,019,215,078 | 2,085,127 | 0.0020 | 0.9980 | 99.58 |
| 4.5 | 988,051,417 | 2,910,912 | 0.0029 | 0.9971 | 99.37 |
| 5.5 | 886,707,371 | 3,439,429 | 0.0039 | 0.9961 | 99.08 |
| 6.5 | 818,929,757 | 2,573,231 | 0.0031 | 0.9969 | 98.69 |
| 7.5 | 763,823,844 | 3,326,110 | 0.0044 | 0.9956 | 98.38 |
| 8.5 | 719,723,943 | 4,203,269 | 0.0058 | 0.9942 | 97.96 |
| 9.5 | 666,203,519 | 2,737,708 | 0.0041 | 0.9959 | 97.38 |
| 10.5 | 611,876,482 | 2,557,107 | 0.0042 | 0.9958 | 96.98 |
| 11.5 | 586,351,276 | 3,173,778 | 0.0054 | 0.9946 | 96.58 |
| 12.5 | 567,585,491 | 4,257,002 | 0.0075 | 0.9925 | 96.06 |
| 13.5 | 546,763,324 | 3,954,890 | 0.0072 | 0.9928 | 95.34 |
| 14.5 | 523,323,536 | 2,003,287 | 0.0038 | 0.9962 | 94.65 |
| 15.5 | 502,555,796 | 1,709,784 | 0.0034 | 0.9966 | 94.28 |
| 16.5 | 471,285,692 | 3,157,085 | 0.0067 | 0.9933 | 93.96 |
| 17.5 | 440,229,102 | 2,511,272 | 0.0057 | 0.9943 | 93.33 |
| 18.5 | 404,334,148 | 2,757,530 | 0.0068 | 0.9932 | 92.80 |
| 19.5 | 388,308,107 | 2,274,601 | 0.0059 | 0.9941 | 92.17 |
| 20.5 | 371,973,018 | 7,040,639 | 0.0189 | 0.9811 | 91.63 |
| 21.5 | 362,983,793 | 7,054,130 | 0.0194 | 0.9806 | 89.89 |
| 22.5 | 345,307,385 | 4,634,589 | 0.0134 | 0.9866 | 88.15 |
| 23.5 | 326,083,461 | 2,998,875 | 0.0092 | 0.9908 | 86.96 |
| 24.5 | 318,206,982 | 1,988,115 | 0.0062 | 0.9938 | 86.16 |
| 25.5 | 302,020,046 | 3,171,986 | 0.0105 | 0.9895 | 85.63 |
| 26.5 | 281,310,252 | 3,378,462 | 0.0120 | 0.9880 | 84.73 |
| 27.5 | 271,768,160 | 1,461,647 | 0.0054 | 0.9946 | 83.71 |
| 28.5 | 256,697,291 | 2,514,443 | 0.0098 | 0.9902 | 83.26 |
| 29.5 | 247,692,216 | 2,228,598 | 0.0090 | 0.9910 | 82.44 |
| 30.5 | 233,444,073 | 4,156,816 | 0.0178 | 0.9822 | 81.70 |
| 31.5 | 205,368,208 | 2,347,788 | 0.0114 | 0.9886 | 80.25 |
| 32.5 | 186,674,044 | 2,282,061 | 0.0122 | 0.9878 | 79.33 |
| 33.5 | 174,980,827 | 1,606,528 | 0.0092 | 0.9908 | 78.36 |
| 34.5 | 166,560,236 | 3,520,318 | 0.0211 | 0.9789 | 77.64 |
| 35.5 | 122,604,792 | 1,392,201 | 0.0114 | 0.9886 | 76.00 |
| 36.5 | 117,684,506 | 1,190,385 | 0.0101 | 0.9899 | 75.14 |
| 37.5 | 108,406,097 | 1,722,382 | 0.0159 | 0.9841 | 74.38 |
| 38.5 | 95,585,114 | 1,111,638 | 0.0116 | 0.9884 | 73.19 |

DUKE ENERGY PROGRESS

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1907-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 82,479,148 | 913,216 | 0.0111 | 0.9889 | 72.34 |
| 40.5 | 77,924,825 | 1,028,426 | 0.0132 | 0.9868 | 71.54 |
| 41.5 | 65,741,401 | 965,293 | 0.0147 | 0.9853 | 70.60 |
| 42.5 | 60,287,696 | 823,356 | 0.0137 | 0.9863 | 69.56 |
| 43.5 | 54,893,152 | 1,397,255 | 0.0255 | 0.9745 | 68.61 |
| 44.5 | 48,051,077 | 799,619 | 0.0166 | 0.9834 | 66.86 |
| 45.5 | 41,185,061 | 578,418 | 0.0140 | 0.9860 | 65.75 |
| 46.5 | 34,703,893 | 724,516 | 0.0209 | 0.9791 | 64.83 |
| 47.5 | 28,134,022 | 303,407 | 0.0108 | 0.9892 | 63.47 |
| 48.5 | 23,911,853 | 433,918 | 0.0181 | 0.9819 | 62.79 |
| 49.5 | 21,977,462 | 200,321 | 0.0091 | 0.9909 | 61.65 |
| 50.5 | 18,286,502 | 440,287 | 0.0241 | 0.9759 | 61.09 |
| 51.5 | 15,147,181 | 177,433 | 0.0117 | 0.9883 | 59.62 |
| 52.5 | 13,122,523 | 79,656 | 0.0061 | 0.9939 | 58.92 |
| 53.5 | 11,952,176 | 287,845 | 0.0241 | 0.9759 | 58.56 |
| 54.5 | 11,285,943 | 106,954 | 0.0095 | 0.9905 | 57.15 |
| 55.5 | 10,970,699 | 132,143 | 0.0120 | 0.9880 | 56.61 |
| 56.5 | 9,930,576 | 130,057 | 0.0131 | 0.9869 | 55.93 |
| 57.5 | 9,757,876 | 11,057 | 0.0011 | 0.9989 | 55.20 |
| 58.5 | 8,779,191 | 111,159 | 0.0127 | 0.9873 | 55.13 |
| 59.5 | 8,570,146 | 53,788 | 0.0063 | 0.9937 | 54.44 |
| 60.5 | 7,914,752 | 119,167 | 0.0151 | 0.9849 | 54.09 |
| 61.5 | 7,780,945 | 378,873 | 0.0487 | 0.9513 | 53.28 |
| 62.5 | 6,510,811 | 12,834 | 0.0020 | 0.9980 | 50.68 |
| 63.5 | 6,442,806 | 22,082 | 0.0034 | 0.9966 | 50.58 |
| 64.5 | 5,923,167 | 321,151 | 0.0542 | 0.9458 | 50.41 |
| 65.5 | 5,510,225 | 166,757 | 0.0303 | 0.9697 | 47.68 |
| 66.5 | 4,128,777 | 29,954 | 0.0073 | 0.9927 | 46.24 |
| 67.5 | 3,322,156 | 60,970 | 0.0184 | 0.9816 | 45.90 |
| 68.5 | 2,979,631 | 21,674 | 0.0073 | 0.9927 | 45.06 |
| 69.5 | 2,142,089 | 2,341 | 0.0011 | 0.9989 | 44.73 |
| 70.5 | 2,127,999 | 35,343 | 0.0166 | 0.9834 | 44.68 |
| 71.5 | 1,776,224 | 12,178 | 0.0069 | 0.9931 | 43.94 |
| 72.5 | 1,762,172 | 2,480 | 0.0014 | 0.9986 | 43.64 |
| 73.5 | 1,759,186 | 30,914 | 0.0176 | 0.9824 | 43.58 |
| 74.5 | 1,728,021 | 13,607 | 0.0079 | 0.9921 | 42.81 |
| 75.5 | 1,703,743 | 130,374 | 0.0765 | 0.9235 | 42.47 |
| 76.5 | 1,354,910 | 38,913 | 0.0287 | 0.9713 | 39.22 |
| 77.5 | 1,254,402 | 11,746 | 0.0094 | 0.9906 | 38.10 |
| 78.5 | 1,214,409 | 20,163 | 0.0166 | 0.9834 | 37.74 |

DUKE ENERGY PROGRESS

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1907-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 1,188,547 | 23,895 | 0.0201 | 0.9799 | 37.11 |
| 80.5 | 1,144,991 | 579 | 0.0005 | 0.9995 | 36.37 |
| 81.5 | 1,132,234 | 53,291 | 0.0471 | 0.9529 | 36.35 |
| 82.5 | 950,097 | 83,855 | 0.0883 | 0.9117 | 34.64 |
| 83.5 | 849,123 | 84,054 | 0.0990 | 0.9010 | 31.58 |
| 84.5 | 731,754 | 92,524 | 0.1264 | 0.8736 | 28.45 |
| 85.5 | 638,886 | 17,149 | 0.0268 | 0.9732 | 24.86 |
| 86.5 | 621,738 | 90 | 0.0001 | 0.9999 | 24.19 |
| 87.5 | 619,458 | 26 | 0.0000 | 1.0000 | 24.19 |
| 88.5 | 541,209 | | 0.0000 | 1.0000 | 24.19 |
| 89.5 | 527,957 | 264,239 | 0.5005 | 0.4995 | 24.19 |
| 90.5 | 259,314 | 22,876 | 0.0882 | 0.9118 | 12.08 |
| 91.5 | 236,438 | 16,521 | 0.0699 | 0.9301 | 11.01 |
| 92.5 | 219,917 | 90,609 | 0.4120 | 0.5880 | 10.25 |
| 93.5 | 129,307 | 1,903 | 0.0147 | 0.9853 | 6.02 |
| 94.5 | 127,404 | 11,542 | 0.0906 | 0.9094 | 5.94 |
| 95.5 | 115,863 | 84,713 | 0.7311 | 0.2689 | 5.40 |
| 96.5 | 31,150 | 1,103 | 0.0354 | 0.9646 | 1.45 |
| 97.5 | 30,047 | | 0.0000 | 1.0000 | 1.40 |
| 98.5 | 30,047 | | 0.0000 | 1.0000 | 1.40 |
| 99.5 | 30,047 | 809 | 0.0269 | 0.9731 | 1.40 |
| 100.5 | 29,238 | | 0.0000 | 1.0000 | 1.36 |
| 101.5 | 29,238 | | 0.0000 | 1.0000 | 1.36 |
| 102.5 | 29,238 | 471 | 0.0161 | 0.9839 | 1.36 |
| 103.5 | 28,767 | | 0.0000 | 1.0000 | 1.34 |
| 104.5 | 28,767 | | 0.0000 | 1.0000 | 1.34 |
| 105.5 | 28,767 | 3,962 | 0.1377 | 0.8623 | 1.34 |
| 106.5 | 24,805 | | 0.0000 | 1.0000 | 1.16 |
| 107.5 | 24,805 | 9,597 | 0.3869 | 0.6131 | 1.16 |
| 108.5 | 15,208 | 15,208 | 1.0000 | | 0.71 |
| 109.5 | | | | | |

DUKE ENERGY PROGRESS

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 1,124,699,083 | 368,882 | 0.0003 | 0.9997 | 100.00 |
| 0.5 | 1,041,595,758 | 528,098 | 0.0005 | 0.9995 | 99.97 |
| 1.5 | 995,412,730 | 825,409 | 0.0008 | 0.9992 | 99.92 |
| 2.5 | 973,402,209 | 1,383,563 | 0.0014 | 0.9986 | 99.83 |
| 3.5 | 944,055,212 | 1,203,189 | 0.0013 | 0.9987 | 99.69 |
| 4.5 | 921,937,155 | 2,718,786 | 0.0029 | 0.9971 | 99.56 |
| 5.5 | 829,509,075 | 2,965,440 | 0.0036 | 0.9964 | 99.27 |
| 6.5 | 771,935,555 | 2,428,763 | 0.0031 | 0.9969 | 98.92 |
| 7.5 | 724,733,339 | 3,015,878 | 0.0042 | 0.9958 | 98.60 |
| 8.5 | 685,693,035 | 4,073,029 | 0.0059 | 0.9941 | 98.19 |
| 9.5 | 634,591,406 | 2,193,047 | 0.0035 | 0.9965 | 97.61 |
| 10.5 | 586,287,602 | 2,182,238 | 0.0037 | 0.9963 | 97.27 |
| 11.5 | 565,018,307 | 2,957,574 | 0.0052 | 0.9948 | 96.91 |
| 12.5 | 549,394,281 | 4,160,503 | 0.0076 | 0.9924 | 96.40 |
| 13.5 | 530,972,584 | 3,776,225 | 0.0071 | 0.9929 | 95.67 |
| 14.5 | 508,603,750 | 1,974,602 | 0.0039 | 0.9961 | 94.99 |
| 15.5 | 488,297,524 | 1,657,202 | 0.0034 | 0.9966 | 94.63 |
| 16.5 | 458,125,414 | 2,967,380 | 0.0065 | 0.9935 | 94.30 |
| 17.5 | 427,361,147 | 2,328,886 | 0.0054 | 0.9946 | 93.69 |
| 18.5 | 393,447,769 | 2,707,136 | 0.0069 | 0.9931 | 93.18 |
| 19.5 | 378,265,741 | 2,232,667 | 0.0059 | 0.9941 | 92.54 |
| 20.5 | 362,930,575 | 6,970,542 | 0.0192 | 0.9808 | 92.00 |
| 21.5 | 354,247,618 | 6,747,612 | 0.0190 | 0.9810 | 90.23 |
| 22.5 | 337,879,442 | 4,593,078 | 0.0136 | 0.9864 | 88.51 |
| 23.5 | 318,396,400 | 2,945,270 | 0.0093 | 0.9907 | 87.31 |
| 24.5 | 310,961,608 | 1,952,735 | 0.0063 | 0.9937 | 86.50 |
| 25.5 | 293,923,152 | 3,078,153 | 0.0105 | 0.9895 | 85.96 |
| 26.5 | 274,813,436 | 3,308,737 | 0.0120 | 0.9880 | 85.06 |
| 27.5 | 266,140,284 | 1,425,945 | 0.0054 | 0.9946 | 84.03 |
| 28.5 | 251,354,229 | 2,459,340 | 0.0098 | 0.9902 | 83.58 |
| 29.5 | 243,338,568 | 2,121,451 | 0.0087 | 0.9913 | 82.76 |
| 30.5 | 229,021,734 | 4,071,598 | 0.0178 | 0.9822 | 82.04 |
| 31.5 | 201,336,701 | 2,281,260 | 0.0113 | 0.9887 | 80.58 |
| 32.5 | 182,776,449 | 2,239,099 | 0.0123 | 0.9877 | 79.67 |
| 33.5 | 171,123,475 | 1,350,156 | 0.0079 | 0.9921 | 78.69 |
| 34.5 | 162,945,433 | 3,351,356 | 0.0206 | 0.9794 | 78.07 |
| 35.5 | 119,236,928 | 1,304,385 | 0.0109 | 0.9891 | 76.47 |
| 36.5 | 114,674,287 | 1,174,887 | 0.0102 | 0.9898 | 75.63 |
| 37.5 | 105,482,088 | 1,699,347 | 0.0161 | 0.9839 | 74.86 |
| 38.5 | 92,737,598 | 1,060,263 | 0.0114 | 0.9886 | 73.65 |

DUKE ENERGY PROGRESS

ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 79,690,268 | 862,374 | 0.0108 | 0.9892 | 72.81 |
| 40.5 | 75,218,367 | 964,324 | 0.0128 | 0.9872 | 72.02 |
| 41.5 | 63,132,558 | 841,880 | 0.0133 | 0.9867 | 71.10 |
| 42.5 | 57,969,440 | 776,214 | 0.0134 | 0.9866 | 70.15 |
| 43.5 | 52,629,741 | 1,396,337 | 0.0265 | 0.9735 | 69.21 |
| 44.5 | 45,864,335 | 799,619 | 0.0174 | 0.9826 | 67.37 |
| 45.5 | 39,012,047 | 565,798 | 0.0145 | 0.9855 | 66.20 |
| 46.5 | 32,545,221 | 718,266 | 0.0221 | 0.9779 | 65.24 |
| 47.5 | 25,983,819 | 288,587 | 0.0111 | 0.9889 | 63.80 |
| 48.5 | 21,964,061 | 416,564 | 0.0190 | 0.9810 | 63.09 |
| 49.5 | 20,214,971 | 200,321 | 0.0099 | 0.9901 | 61.89 |
| 50.5 | 17,591,273 | 440,287 | 0.0250 | 0.9750 | 61.28 |
| 51.5 | 14,590,867 | 177,433 | 0.0122 | 0.9878 | 59.75 |
| 52.5 | 12,601,412 | 79,071 | 0.0063 | 0.9937 | 59.02 |
| 53.5 | 11,622,777 | 287,845 | 0.0248 | 0.9752 | 58.65 |
| 54.5 | 11,117,433 | 106,726 | 0.0096 | 0.9904 | 57.20 |
| 55.5 | 10,830,266 | 132,143 | 0.0122 | 0.9878 | 56.65 |
| 56.5 | 9,879,149 | 130,037 | 0.0132 | 0.9868 | 55.96 |
| 57.5 | 9,709,151 | 11,057 | 0.0011 | 0.9989 | 55.22 |
| 58.5 | 8,730,565 | 110,769 | 0.0127 | 0.9873 | 55.16 |
| 59.5 | 8,535,984 | 53,788 | 0.0063 | 0.9937 | 54.46 |
| 60.5 | 7,881,438 | 119,167 | 0.0151 | 0.9849 | 54.11 |
| 61.5 | 7,748,722 | 378,873 | 0.0489 | 0.9511 | 53.30 |
| 62.5 | 6,478,619 | 12,834 | 0.0020 | 0.9980 | 50.69 |
| 63.5 | 6,413,008 | 22,062 | 0.0034 | 0.9966 | 50.59 |
| 64.5 | 5,893,878 | 321,151 | 0.0545 | 0.9455 | 50.42 |
| 65.5 | 5,480,966 | 166,757 | 0.0304 | 0.9696 | 47.67 |
| 66.5 | 4,103,570 | 29,954 | 0.0073 | 0.9927 | 46.22 |
| 67.5 | 3,296,974 | 60,970 | 0.0185 | 0.9815 | 45.88 |
| 68.5 | 2,964,048 | 21,674 | 0.0073 | 0.9927 | 45.03 |
| 69.5 | 2,142,051 | 2,341 | 0.0011 | 0.9989 | 44.70 |
| 70.5 | 2,127,999 | 35,343 | 0.0166 | 0.9834 | 44.65 |
| 71.5 | 1,776,224 | 12,178 | 0.0069 | 0.9931 | 43.91 |
| 72.5 | 1,762,172 | 2,480 | 0.0014 | 0.9986 | 43.61 |
| 73.5 | 1,759,186 | 30,914 | 0.0176 | 0.9824 | 43.55 |
| 74.5 | 1,728,021 | 13,607 | 0.0079 | 0.9921 | 42.79 |
| 75.5 | 1,703,743 | 130,374 | 0.0765 | 0.9235 | 42.45 |
| 76.5 | 1,354,910 | 38,913 | 0.0287 | 0.9713 | 39.20 |
| 77.5 | 1,254,402 | 11,746 | 0.0094 | 0.9906 | 38.07 |
| 78.5 | 1,214,409 | 20,163 | 0.0166 | 0.9834 | 37.72 |

DUKE ENERGY PROGRESS

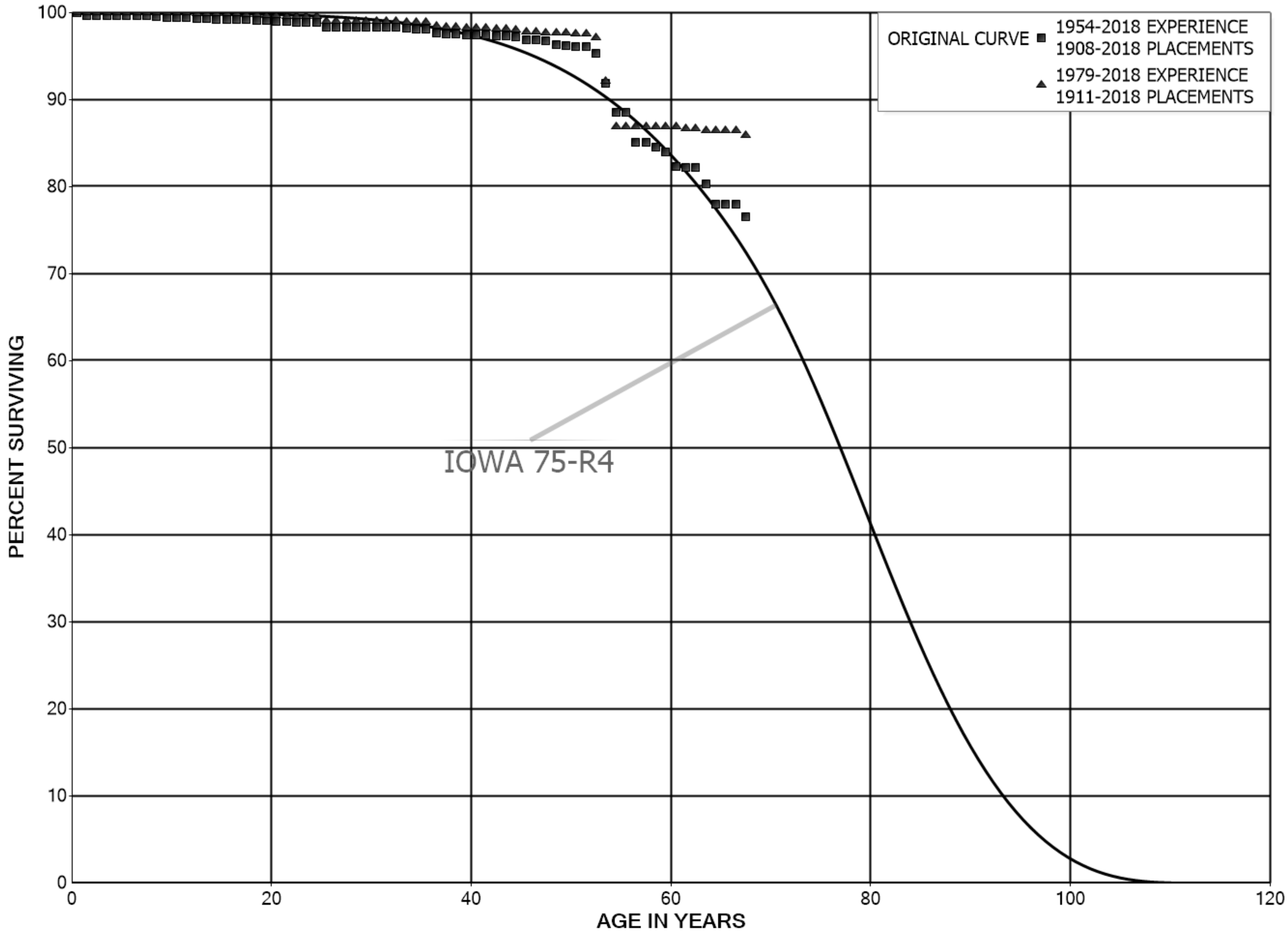
ACCOUNT 353 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2018 EXPERIENCE BAND 1979-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 79.5 | 1,188,547 | 23,895 | 0.0201 | 0.9799 | 37.09 |
| 80.5 | 1,144,991 | 579 | 0.0005 | 0.9995 | 36.35 |
| 81.5 | 1,132,234 | 53,291 | 0.0471 | 0.9529 | 36.33 |
| 82.5 | 950,097 | 83,855 | 0.0883 | 0.9117 | 34.62 |
| 83.5 | 849,123 | 84,054 | 0.0990 | 0.9010 | 31.56 |
| 84.5 | 731,754 | 92,524 | 0.1264 | 0.8736 | 28.44 |
| 85.5 | 638,886 | 17,149 | 0.0268 | 0.9732 | 24.84 |
| 86.5 | 621,738 | 90 | 0.0001 | 0.9999 | 24.18 |
| 87.5 | 619,458 | 26 | 0.0000 | 1.0000 | 24.17 |
| 88.5 | 541,209 | | 0.0000 | 1.0000 | 24.17 |
| 89.5 | 527,957 | 264,239 | 0.5005 | 0.4995 | 24.17 |
| 90.5 | 259,314 | 22,876 | 0.0882 | 0.9118 | 12.07 |
| 91.5 | 236,438 | 16,521 | 0.0699 | 0.9301 | 11.01 |
| 92.5 | 219,917 | 90,609 | 0.4120 | 0.5880 | 10.24 |
| 93.5 | 129,307 | 1,903 | 0.0147 | 0.9853 | 6.02 |
| 94.5 | 127,404 | 11,542 | 0.0906 | 0.9094 | 5.93 |
| 95.5 | 115,863 | 84,713 | 0.7311 | 0.2689 | 5.39 |
| 96.5 | 31,150 | 1,103 | 0.0354 | 0.9646 | 1.45 |
| 97.5 | 30,047 | | 0.0000 | 1.0000 | 1.40 |
| 98.5 | 30,047 | | 0.0000 | 1.0000 | 1.40 |
| 99.5 | 30,047 | 809 | 0.0269 | 0.9731 | 1.40 |
| 100.5 | 29,238 | | 0.0000 | 1.0000 | 1.36 |
| 101.5 | 29,238 | | 0.0000 | 1.0000 | 1.36 |
| 102.5 | 29,238 | 471 | 0.0161 | 0.9839 | 1.36 |
| 103.5 | 28,767 | | 0.0000 | 1.0000 | 1.34 |
| 104.5 | 28,767 | | 0.0000 | 1.0000 | 1.34 |
| 105.5 | 28,767 | 3,962 | 0.1377 | 0.8623 | 1.34 |
| 106.5 | 24,805 | | 0.0000 | 1.0000 | 1.15 |
| 107.5 | 24,805 | 9,597 | 0.3869 | 0.6131 | 1.15 |
| 108.5 | 15,208 | 15,208 | 1.0000 | | 0.71 |
| 109.5 | | | | | |

DUKE ENERGY PROGRESS
ACCOUNT 354 TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



DUKE ENERGY PROGRESS

ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 0.0 | 78,664,973 | 982 | 0.0000 | 1.0000 | 100.00 |
| 0.5 | 65,261,308 | 215,189 | 0.0033 | 0.9967 | 100.00 |
| 1.5 | 61,191,752 | | 0.0000 | 1.0000 | 99.67 |
| 2.5 | 61,144,505 | | 0.0000 | 1.0000 | 99.67 |
| 3.5 | 61,156,855 | | 0.0000 | 1.0000 | 99.67 |
| 4.5 | 60,564,286 | 25,286 | 0.0004 | 0.9996 | 99.67 |
| 5.5 | 58,790,455 | 3,528 | 0.0001 | 0.9999 | 99.63 |
| 6.5 | 58,628,065 | 19,498 | 0.0003 | 0.9997 | 99.62 |
| 7.5 | 58,595,914 | 46,013 | 0.0008 | 0.9992 | 99.59 |
| 8.5 | 58,449,625 | 39,008 | 0.0007 | 0.9993 | 99.51 |
| 9.5 | 57,978,996 | 24,550 | 0.0004 | 0.9996 | 99.44 |
| 10.5 | 56,201,421 | 13,346 | 0.0002 | 0.9998 | 99.40 |
| 11.5 | 56,179,493 | 42,334 | 0.0008 | 0.9992 | 99.38 |
| 12.5 | 56,386,583 | 15 | 0.0000 | 1.0000 | 99.30 |
| 13.5 | 56,253,932 | 43,547 | 0.0008 | 0.9992 | 99.30 |
| 14.5 | 56,250,594 | 13,380 | 0.0002 | 0.9998 | 99.23 |
| 15.5 | 56,421,564 | 13,113 | 0.0002 | 0.9998 | 99.20 |
| 16.5 | 56,450,308 | 20,508 | 0.0004 | 0.9996 | 99.18 |
| 17.5 | 56,561,792 | 24,539 | 0.0004 | 0.9996 | 99.14 |
| 18.5 | 56,557,467 | 38,417 | 0.0007 | 0.9993 | 99.10 |
| 19.5 | 56,446,458 | 29,957 | 0.0005 | 0.9995 | 99.03 |
| 20.5 | 56,218,892 | 30,679 | 0.0005 | 0.9995 | 98.98 |
| 21.5 | 56,369,066 | 30,934 | 0.0005 | 0.9995 | 98.93 |
| 22.5 | 56,337,090 | 28,075 | 0.0005 | 0.9995 | 98.87 |
| 23.5 | 56,208,041 | 7,213 | 0.0001 | 0.9999 | 98.82 |
| 24.5 | 56,662,259 | 298,043 | 0.0053 | 0.9947 | 98.81 |
| 25.5 | 56,363,772 | 7,725 | 0.0001 | 0.9999 | 98.29 |
| 26.5 | 52,286,671 | 15,543 | 0.0003 | 0.9997 | 98.28 |
| 27.5 | 52,706,341 | 242 | 0.0000 | 1.0000 | 98.25 |
| 28.5 | 52,866,237 | 990 | 0.0000 | 1.0000 | 98.25 |
| 29.5 | 52,874,454 | 3,065 | 0.0001 | 0.9999 | 98.25 |
| 30.5 | 53,172,484 | 126 | 0.0000 | 1.0000 | 98.24 |
| 31.5 | 55,881,996 | | 0.0000 | 1.0000 | 98.24 |
| 32.5 | 55,774,904 | 18,789 | 0.0003 | 0.9997 | 98.24 |
| 33.5 | 36,624,071 | 34,423 | 0.0009 | 0.9991 | 98.21 |
| 34.5 | 34,582,544 | 4,921 | 0.0001 | 0.9999 | 98.11 |
| 35.5 | 32,578,054 | 153,778 | 0.0047 | 0.9953 | 98.10 |
| 36.5 | 18,387,304 | 16,350 | 0.0009 | 0.9991 | 97.64 |
| 37.5 | 17,803,416 | 4,347 | 0.0002 | 0.9998 | 97.55 |
| 38.5 | 17,765,103 | 18,303 | 0.0010 | 0.9990 | 97.53 |

DUKE ENERGY PROGRESS

ACCOUNT 354 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2018 EXPERIENCE BAND 1954-2018

| AGE AT BEGIN OF INTERVAL | EXPOSURES AT BEGINNING OF AGE INTERVAL | RETIREMENTS DURING AGE INTERVAL | RETMT RATIO | SURV RATIO | PCT SURV BEGIN OF INTERVAL |
|---|---|---|---|---|---|
| 39.5 | 17,177,380 | 3,059 | 0.0002 | 0.9998 | 97.43 |
| 40.5 | 16,820,818 | 6,242 | 0.0004 | 0.9996 | 97.41 |
| 41.5 | 16,258,770 | 11,630 | 0.0007 | 0.9993 | 97.37 |
| 42.5 | 16,153,245 | 4,206 | 0.0003 | 0.9997 | 97.30 |
| 43.5 | 13,892,446 | 14,078 | 0.0010 | 0.9990 | 97.28 |
| 44.5 | 13,892,195 | 41,614 | 0.0030 | 0.9970 | 97.18 |
| 45.5 | 13,378,973 | 1,693 | 0.0001 | 0.9999 | 96.89 |
| 46.5 | 9,692,847 | 13,361 | 0.0014 | 0.9986 | 96.88 |
| 47.5 | 8,494,121 | 36,339 | 0.0043 | 0.9957 | 96.74 |
| 48.5 | 8,516,288 | 15,158 | 0.0018 | 0.9982 | 96.33 |
| 49.5 | 8,076,169 | 10,782 | 0.0013 | 0.9987 | 96.16 |
| 50.5 | 7,436,779 | 1,124 | 0.0002 | 0.9998 | 96.03 |
| 51.5 | 6,227,122 | 49,884 | 0.0080 | 0.9920 | 96.01 |
| 52.5 | 3,799,737 | 134,784 | 0.0355 | 0.9645 | 95.24 |
| 53.5 | 2,808,664 | 103,956 | 0.0370 | 0.9630 | 91.87 |
| 54.5 | 2,628,595 | | 0.0000 | 1.0000 | 88.47 |
| 55.5 | 2,448,608 | 93,420 | 0.0382 | 0.9618 | 88.47 |
| 56.5 | 2,333,129 | | 0.0000 | 1.0000 | 85.09 |
| 57.5 | 2,239,870 | 16,275 | 0.0073 | 0.9927 | 85.09 |
| 58.5 | 2,169,635 | 14,191 | 0.0065 | 0.9935 | 84.47 |
| 59.5 | 2,118,612 | 40,156 | 0.0190 | 0.9810 | 83.92 |
| 60.5 | 1,978,691 | 4,453 | 0.0023 | 0.9977 | 82.33 |
| 61.5 | 1,972,950 | 548 | 0.0003 | 0.9997 | 82.14 |
| 62.5 | 1,972,402 | 43,954 | 0.0223 | 0.9777 | 82.12 |
| 63.5 | 1,928,448 | 56,000 | 0.0290 | 0.9710 | 80.29 |
| 64.5 | 1,872,448 | 586 | 0.0003 | 0.9997 | 77.96 |
| 65.5 | 1,871,862 | | 0.0000 | 1.0000 | 77.94 |
| 66.5 | 1,851,324 | 32,893 | 0.0178 | 0.9822 | 77.94 |
| 67.5 | 1,788,385 | 815 | 0.0005 | 0.9995 | 76.55 |
| 68.5 | 1,785,512 | 494 | 0.0003 | 0.9997 | 76.52 |
| 69.5 | 1,785,018 | 954 | 0.0005 | 0.9995 | 76.49 |
| 70.5 | 1,784,064 | | 0.0000 | 1.0000 | 76.45 |
| 71.5 | 1,784,064 | 6 | 0.0000 | 1.0000 | 76.45 |
| 72.5 | 1,784,059 | 3,207 | 0.0018 | 0.9982 | 76.45 |
| 73.5 | 1,780,851 | | 0.0000 | 1.0000 | 76.32 |
| 74.5 | 1,780,851 | | 0.0000 | 1.0000 | 76.32 |
| 75.5 | 1,780,851 | | 0.0000 | 1.0000 | 76.32 |
| 76.5 | 1,780,851 | 97,347 | 0.0547 | 0.9453 | 76.32 |
| 77.5 | 1,683,504 | 76,366 | 0.0454 | 0.9546 | 72.14 |
| 78.5 | 1,607,138 | 1,907 | 0.0012 | 0.9988 | 68.87 |

Larry E. Hatcher
Stipulated Testimony from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Larry E. Hatcher
Stipulated Exhibits from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

February 10, 2020

**VIA ELECTRONIC FILING**

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

**RE: Initial Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC**
**Docket No. E-100, Sub 161**

Dear Ms. Campbell:

Pursuant to the Commission's *Order Requiring Information, Requesting Comments, and Initiating Rulemaking* issued February 4, 2019 and the subsequent extensions of time granted by the Commission in the above-referenced docket, enclosed for filing are the Initial Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 161

| | | |
|---|---|---|
| In the Matter of<br>Commission Rules Related to Customer Billing Data | )<br>)<br>)<br>)<br>) | INITIAL JOINT COMMENTS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC |

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies"), who, pursuant to the North Carolina Utilities Commission's ("Commission" or "NCUC") February 4, 2019 *Order Requiring Information, Requesting Comments, and Initiating Rulemaking* in the above-captioned docket, submit their initial comments on the proposed Commission Rules R8-7, R8-8 and R8-51 filed by the Public Staff of the North Carolina Utilities Commission ("Public Staff"). For the reasons set forth below, the Companies generally support the Public Staff's proposed Rules; however, the Companies do not support the Public Staff's proposal to impose additional requirements that go into effect January 1, 2022, on the Companies.

A. <u>Commission Rule R8-7 – Information for Customers and Rule R8-8 – Meter Readings, Bill Forms and Meter Data</u>

The Companies generally agree with the Public Staff's proposed revisions to Commission Rule R8-7 and R8-8. For the most part, these proposed revisions and proposed revisions to Rule R8-51 refer to energy "usage" data. Therefore, with respect to the Public Staff's proposed Rule R8-7(b)(2), the Companies suggest that the word "consumption" be struck and replaced with the word "usage" to maintain consistency with the other provisions of this Rule, Rule R8-8 and R8-51.

The Companies additionally note that, as proposed, Commission Rule R8-7(b) states that the utility annually shall provide its customers certain information, either by mail or electronically, including instructions on how to access their billing records pursuant to Rule R8-8(f). Specifically, Rule R8-7(c) provides that once metering and billing technology required for such analysis is in place, each electric utility shall annually inform its customers that they may request from the utility a rate analysis of applicable rate schedules for the customer upon establishing a sufficient usage history at a premise or provide the customer a mechanism from which to obtain this information. Moreover, the Public Staff's proposed Commission Rule R8-8(b) directs the utilities to minimize the frequency of estimated bills. Rule R8-8(b)(3) provides that:

> In the event the utility is unable to provide a bill based on metered service for more than three consecutive billing cycles, the utility shall inform the customer that it is unable to provide a bill for metered service and that the customer may request the reason for estimating the bill and how the utility plans to resolve the problem causing the bill to be estimated.

The Companies do not object to these proposed revisions, but note in these Joint Comments that to comply with them, the Companies must complete implementation of their Customer Connect Program. They project that Customer Connect will be implemented for DEC in April 2021 and for DEP in April 2022. Once Customer Connect is deployed, the Companies will need to accumulate 13 months of interval data per customer/per account in the new system before they can offer the Annual Rate Review and the Rate comparison capabilities as described in the Rules. If these Rules are made effective prior to full deployment of Customer Connect, the Companies may seek of waiver of their application during the interim.

Proposed Commission Rule R8-8(d) states that:

> The utility shall strive to maintain consistency between the data observed at the meter face and that maintained in the billing and customer data systems, such that the customer can reasonably understand any discrepancy between the data that is observable at the meter face with the data that is available through an electronic platform provided by the utility to communicate said data with the customer.

This provision is inconsistent with DEC's service regulations that are currently approved and on file at the NCUC. These regulations provide that:

> Meters will be read and bills rendered monthly. Meter readings may be obtained manually on the customer's premises, or remotely using radio frequency or other automated meter reading technology. Billing statements will show the readings of the meter at the beginning and end of the billing period, except; however, when interval load data is used to determine the bill under certain rate schedules or riders, only the billing units may be shown.

This service regulation reflects that, for accounts billed with detailed information by rating period, such as Time of Use rates, the Companies do not have the ability to show all components on the face of the meter. Therefore, the Companies recommend that this provision be clarified to ensure that the Companies remain compliant with the NCUC's Rules.

B. <u>Commission Rule R8-51</u>

As with Commission Rules R8-7 and R8-8, the Companies are generally supportive of the Public Staff's proposed Rule R8-51, and they appreciate the Public Staff's willingness to work toward striking a balance between protecting the customers' data and implementing an efficient and workable administrative process for the utilities to provide access that does not impose additional, unnecessary costs on ratepayers. The proposed Rule is consistent with procedures that the Companies have already had in place because of the requirements of their Code of Conduct. The Companies do not support, however, the portions of the Public Staff's revisions to R8-51 that they propose to go into effect in two years for several reasons. Specifically, the Public Staff has proposed the following:

Effective January 1, 2022, subsection (d) of Commission Rule R8-51 is amended to read:

(d) A utility shall maintain at least 24 months of customer data in sufficient detail to assist customers in understanding their energy usage. The frequency interval of the data must be commensurate with the meter or network technology used to serve the customer. Customer data shall be maintained and ~~provided~~ made available to customers and customer-authorized third parties in electronic machine-readable format that conforms to the latest version of the North American Energy Standard Board's (NAESB) Reg 21, the Energy Services Provider Interface (ESPI), or a Commission approved electronic machine readable format that conforms to nationally recognized standards and best practices ~~commensurate with the meter or network technology use to serve the customer~~.

Effective January 1, 2022, subsections (g) and (h) of R8-51 are amended to read:

(g) A utility shall not disclose customer data to a third party unless the customer provides consent by either ~~submits~~ submitting a ~~paper or electronically signed~~ consent form or through the utility's electronic consent process. The utility shall conspicuously post the form on the utility's website in either electronic or printable format. The utility must authenticate the customer identity and consent to release customer data before acting upon the consent form.

(h) A utility ~~may~~ shall make available an electronic customer consent process for disclosure of customer data to a third party, provided that the utility authenticates the customer's identity and consent to release customer data. The contents of the electronic consent process must generally follow the format of the Commission-prescribed consent form, and include the elements to be provided pursuant to this rule.

As an initial matter, and, as noted throughout these Joint Comments, the Companies are in the process of implementing their Customer Connect Program. Implementation of these proposed Rule amendments in January 2022 will add risk to the deployment of the

Customer Connect Program for DEC (April 2021) and DEP (April 2022). To allow for successful testing, training, conversion and implementation of the core solution, the Companies must freeze changes to many IT systems and business applications starting in 2020. Therefore, from a practical and technical standpoint, the Companies believe these proposed amendments would jeopardize their deployment of the benefits of Customer Connect to their customers.

Additionally, as the Companies notified the Commission on October 15, 2019, in Docket No. E-100, Sub 157, the Companies are currently implementing customer data access functionality like the access provided by "Green Button: Download My Data" functionality. The Companies' web platforms are being migrated to the cloud and upgraded for stability and scalability to support multiple efforts across the Duke Energy Corporation enterprise with projected conclusion to the implementation scheduled for first quarter 2020. Additionally, DEC and DEP customers with smart meters are already able to view and download their electric usage data from the Companies' websites in a standardized format. These customers can view and download their hourly and daily electric usage information from the online customer portal and through mid-cycle notifications with the Usage Alerts program.

The Companies have previously reviewed the Green Button Connect functionality contemplated by these amendments. First, the Companies' survey of their customers did not reveal a customer demand that outweighed the projected costs to implement. Second, as discussed, the Companies already have a process to field third-party data requests for customer usage data and billing information. The potential risks of third-party involvement in that process should be fully vetted before a Commission Rule requires it, even if the requirement begins in 23 months. Third-party access could require a stringent approval process with significant security requirements, leading to potential resource challenges as requests line up in a queue for data. Therefore, the proposed amendments do not serve the Companies' customers' best interests as they introduce security and other risks, as well as additional administrative costs and burdens into this process. The Companies respectfully request that they be struck from the Rule.

Conclusion

The Companies understand that the Public Staff intends to request that the Commission allow the parties to file reply comments on these proposed Rules. The Companies agree and join in this request because of the importance of these Rules to their customers and to the Companies' own compliance efforts.

Respectfully submitted, this the 10th day of February, 2020.

Kendrick C. Fentress

Kendrick C. Fentress
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*ATTORNEY FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC*

**CERTIFICATE OF SERVICE**

I certify that a copy of the Initial Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, in Docket No. E-100, Sub 161, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 10th day of February, 2020.

Kendrick C. Fentress

_______________________________
Kendrick C. Fentress
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Docket No. E-7, Sub 1214A



**Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (jointly, the Companies)**
**Docket No. E-100, Sub 161**
**Public Staff Data Request No. 1**
**Date Sent: April 18, 2019**
**Due Date: April 29, 2019**

**Requested By: Jack Floyd**
**Phone #: 919-715-9018**
**Email: jack.floyd@psncuc.nc.gov**

**Public Staff Legal Contact: Heather Fennell**
**Phone #: 919- 715-0970**
**Email: heather.fennell@psncuc.nc.gov**

10. Please explain how "My Duke Data Download" program compares to the Green Button Alliance's "Green Button Connect My Data (CMD) standard."[1] The response should specifically identify the any inconsistencies between the Duke program and the CMD standard.

**Response provided by Joe Thomas, Director of Enhanced Customer Solutions**

**Response:** This request is asking to compare two very different programs. The My Duke Data Download will allow customers to download their data, in a standardized format, and use it however they choose. This functionality would more appropriate compare with the Green Button Download My Data and will be available to customers in late 2019. The Green Button Connect My Data utilizes the same the same data format standard, but the data would be automatically provided to approved 3rd parties. Duke Energy does not plan to offer this functionality.

[1] https://www.greenbuttonalliance.org/assets/docs/Collateral/2018-08%20Green%20Button%20CMD%20and%20Certification%20Data%20Sheet.pdf

AGO Hatcher Cross Exhibit 3
Docket No. E-7, Sub 1214A



**Executive Summary**

The Green Button initiative enables electric utility customers to download detailed electric usage information from their utility website in a standardized format. Proponents claim the Green Button initiative will accelerate the development of tools that energy consumers can utilize to analyze and monitor usage information.

Duke Energy currently enables its electric utility customers to view and download detailed electric usage information from its own website in a standardized format. This functionality has been in place since Duke Energy Carolinas ("DEC") began installing its Advanced Metering Infrastructure (AMI) several years ago. DEC and Duke Energy Progress ("DEP") customers with AMI meters can further access their detailed electric usage information through the Usage Alerts program. It is important to note that Duke Energy's customers are already capable of using the detailed usage information made available by the Companies to change their usage patterns and reduce their bills.

As Duke Energy assesses its compatibility with Green Button Download and Green Button Connect functionalities, the organization continues to evaluate the following:

1) Could Green Button adversely impact the relationship between Duke Energy and its customers?
2) Will customers' information be protected and does the utility have responsibility and or liability if customers' information is misused?
3) Who bears the burden of supporting customers and app developers when questions arise around energy usage information and the use of Green Button?
4) How does the utility recover costs for a continually evolving standard like the Green Button?
5) How to differentiate between customer conservation enabled by the utility and conservation enabled by third parties?
6) Can the utility claim impacts for customer conservation on Green Button activity?

The below analysis explores Duke Energy's 1) decision to enable functionality consistent with the Green Button Download protocols and 2) the cost-benefit analysis as it relates to implementing and offering Green Button Connect functionality.

**Green Button Download**

By late 2019, customers will be able to log into 'MyAccount' on the Duke Energy website and click the "My Duke Data Download" to download energy consumption data in the standardized format defined by the Green Button standard. This functionality is available if the customer has historical AMI usage data available. Thirteen months of data is permitted to be downloaded and customers are then permitted to use the data as they desire.

It is critical to weigh customer demand for standardized usage data download functionality. To do this, Duke Energy reviewed customers in the Carolinas, between two jurisdictions – DEC and DEP - to understand how many customers viewed their "Usage Analysis" since early 2018. As noted previously, this data regarding current customers viewing their detailed energy usage is possible because Duke Energy's customers already have access to download their usage data through the on-line Service Portal. While the current data format does not match the standardized Green Button format, the data does aim to provide customers with historical data to be used in similar ways.

Of approximately 2.9 million customers in the DEC and DEP jurisdictions with access to their Usage Analysis report in 2018, only a small number of customers viewed their usage – approx. 140,700 in DEC and 12,500 in DEP (see tables below). Note: the numbers below reflect view by session, not unique users, and correlate with availability of Usage Analysis to the customers.

| DEC | | |
|---|---|---|
| **Month** | **Session views of Usage Analysis page** | **Sessions using graph drop down*** |
| Feb-18 | 1,540 | 704 |
| Mar-18 | 2,195 | 897 |
| Apr-18 | 2,197 | 781 |
| May-18 | 8,192 | 2,909 |
| Jun-18 | 13,994 | 5,374 |
| Jul-18 | 15,089 | 5,985 |
| Aug-18 | 14,322 | 5,418 |
| Sep-18 | 8,570 | 3,260 |
| Oct-18 | 12,981 | 5,003 |
| Nov-18 | 16,439 | 6,334 |
| Dec-18 | 17,155 | 6,919 |
| Jan-19 | 28,058 | 10,739 |
| **Total** | **140,732** | **54,323** |

| DEP | | |
|---|---|---|
| **Month** | **Session views of Usage Analysis page** | **Sessions using graph drop down*** |
| Feb-18 | | |
| Mar-18 | | |
| Apr-18 | | |
| May-18 | | |
| Jun-18 | | |
| Jul-18 | | |
| Aug-18 | 690 | 271 |
| Sep-18 | 833 | 399 |
| Oct-18 | 1,052 | 467 |
| Nov-18 | 2,051 | 1,006 |
| Dec-18 | 2,829 | 1,393 |
| Jan-19 | 5,064 | 2,314 |
| **Total** | **12,519** | **5,850** |

*This *may* indicate that these customers further engage with their usage analysis.

**Green Button Connect**

***Cost-Benefit Analysis[1]***

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | 5 Year Summary |
|---|---|---|---|---|---|---|
| **Total Costs** | $1,502,000 | $52,000 | $52,000 | $52,000 | $52,000 | $1,710,000 |
| **Set-up** | $250,000 | $0 | $0 | $0 | $0 | $250,000 |
| **Integration - Download My Data** | $600,000 | $0 | $0 | $0 | $0 | $600,000 |
| **Integration - Connect My Data** | $600,000 | $0 | $0 | $0 | $0 | $600,000 |
| **Maintenance & Operations** | $52,000 | $52,000 | $52,000 | $52,000 | $52,000 | $260,000 |
| **Benefit /cost savings to customers*** | $281,610 | $281,610 | $281,610 | $281,610 | $281,610 | $1,408,050 |
| **Net Benefit** | ($1,220,390) | $229,610 | $229,610 | $229,610 | $229,610 | ($301,950) |

**Based on 2018 (see above), DEC and DEP saw approx. 60,173 sessions in which customers further engaged with their usage analysis. For estimation purposes, and while 60,173 does not represent unique customers, this analysis assumes 10 percent of the 60,173 (6,017) would be likely to use Green Button Connect. Based on an average monthly bill of $130 and a three percent bill savings for this customer population of 6,017, customers may experience a bill reduction of approximately $281,610 per year. See sensitivity analysis below:*

[1] As discussed in more detail below, this analysis is preliminary as several inputs are difficult to quantify.

Bill Reduction Sensitivity Analysis:

| | | | Bill Savings | | |
|---|---|---|---|---|---|
| | | | 5% | 3% | 1% |
| Customers | 100% | 60,173 | $4,693,494 | $2,816,096 | $938,699 |
| | 75% | 45,130 | $3,520,121 | $2,112,072 | $704,024 |
| | 50% | 30,087 | $2,346,747 | $1,408,048 | $469,349 |
| | 25% | 15,043 | $1,173,374 | $704,024 | $234,675 |
| | 10% | 6,017 | $469,349 | $281,610 | $93,870 |
| | 5% | 3,009 | $234,675 | $140,805 | $46,935 |

***Cost Benefit Detail***

| Item name | Timeframe | Estimated cost | Notes |
|---|---|---|---|
| **Set-up (Download & Connect)** | One-time | • $50,000 per platform (3-5 platforms estimated)<br>• $250,000 max cost | Includes costs related to developing a similar Green Button functionality, including but not limited to:<br>• Front-end solutions: interfaces and applications that users interact with directly<br>• Cloud services: computing resources and services that support deployment of Green Button and provide access to its applications, resources and services<br>• Green Button platform: technical foundation that allows multiple products to be built within the same framework and executed successfully<br>• Developing & testing: management of integration, registration, risk, assessment, issues, etc.<br>• Testing of security and privacy mechanisms and protocols |
| **Integration (Download only)** | One-time | $600,000 | Costs required to integrate Green Button with Duke Energy's data systems and processes, including but not limited to:<br>• Customer information system extract, transform, load (ETL) protocols<br>• Other integration costs: integration with customer portals, meter data, external testing and validation, etc.<br>Note: timeframe may necessitate "two pies" (note: one pie is equivalent to four, three-week sprints at $300,000 each). |
| **Integration (Connect only)** | One-time | $300,000 | Costs required to integrate Green Button with Duke Energy's data systems and processes, including but not limited to:<br>• Customer information system extract, transform, load (ETL) protocols<br>• Other integration costs: integration with customer portals, meter data, external testing and validation, etc.<br>Note: timeframe may necessitate "one pie" at $300,000. |

| | | | |
|---|---|---|---|
| **Maintenance & Operations** | Annual | • $1 per customer<br>• $50,000 (estimate of 50,000 customers) | Costs required to maintain the functionality and manage third-party solution provider application registration, including but not limited to:<br>• Maintenance and on-going operations, which address issues to improve performance and or incorporate changes to the standard<br>• Miscellaneous<br>Note: In DEC, there are approx. 2.5M customers with AMI meters. Of these, only approx. 52,000 customers engaged with their usage analysis within a year's time. |

As stated above, there are many unknowns regarding the Green Button Connect platform, making estimation of such functionality difficult to assess. For this effort, we have assumed an agile methodology approach, and the estimate has been determined by the number of sprints ("pies") needed to achieve the desired outcome. The architectural approach is currently unknown and may impact the estimate dramatically. There are also many unknowns surrounding the application, approval, monitoring, and maintenance of 3rd parties. Decisions in this area will impact the estimate for on-going expenses. Moreover, the capabilities for a customer to authorize and deauthorize have also not been included in this estimate.

The Company will need several refinement sessions to further estimate this effort, and these sessions should conclude late in Q3, 2019.

***Duke Energy's Position***

Duke Energy has decided to defer Green Button Connect functionality for the immediate future; the Company does not believe there is adequate customer demand associated with the projected costs to implement. Additionally, given the North Carolina Utilities Commission's February 4, 2019, Order opening a docket (Docket No. E-100, Sub 161) to establish rules related to electric customer billing data, the Company believes that it would be premature to make a decision or even consider its cost benefit analysis complete at this time. Without fully understanding the rules pertaining to data access, it is not prepared to assume the risks associated with the automated transfer of energy consumption data from customers to third parties. A summary of risks is provided below.

While Duke Energy has a process to field third party data requests for customer usage and billing information, potential risks of third-party involvement need to be fully vetted. Customers and utilities may be subjected to unauthorized data access by third parties. Usage data is highly coveted by competitors in similar markets because they can perform analysis which enables them to market different products and services to Duke Energy customers. For example, SDG&E explained that third parties email SDG&E customers asking for their account information to provide free analysis and then build automated routines (bots) to access the "Download My Data" capability on the site. With authorized access to customer data, Duke Energy is subjected to potential mishandling and misuse of data and any associated legal ramifications.

Additionally, third party access could require a stringent approval process with significant security requirements, leading to potential resource challenges. For example, a similarly-sized utility noted that they have five Green Button Connect Enabled Third Parties and another three in queue. Each of the third parties in the queue require significant development and testing time from their resources.

Other risks could include:

- Regulatory ramification and costs associated with keeping pace with evolving regulations;
- Regulatory impacts regarding the appropriate vetting and approval of third-party access to data;
- Lack of customer demand

In summation, Duke Energy believes it is in the best interest of customers to offer usage data download functionality consistent with the Green Button protocols at this time, however, given uncertainty regarding regulatory rules pertaining to data access and the customer benefit associated with this functionality, the Company is not moving forward with implementing the Green Button Connect platform at this time. The Company will continue to monitor and track customer demand for the Green Button Connect functionality and will potentially revisit the Green Button Connect functionality in the future.

July 17, 2020

**VIA ELECTRONIC FILING**

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

**RE: Joint Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC**
**Docket No. E-100, Sub 161**

Dear Ms. Campbell:

Pursuant to the Commission's *Order Requiring Information, Requesting Comments, and Initiating Rulemaking* issued February 4, 2019, the Commission's May 26, 2020 *Order Requesting Reply Comments,* and the subsequent extensions of time granted by the Commission in the above-referenced docket, enclosed for filing are the Joint Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Kendrick C. Fentress

Kendrick C. Fentress

Enclosure

cc: Parties of Record

**CERTIFICATE OF SERVICE**

I certify that a copy of the Joint Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, in Docket No. E-100, Sub 161, has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 17th day of July, 2020.

Kendrick C. Fentress

Kendrick C. Fentress
Associate General Counsel
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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 161

| | | |
|---|---|---|
| In the Matter of<br>Commission Rules Related to Electric Customer Billing Data | ) | JOINT REPLY COMMENTS OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC |

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies"), pursuant to the North Carolina Utilities Commission's ("Commission" or "NCUC") February 4, 2019 *Order Requiring Information, Requesting Comments, and Initiating Rulemaking*, and May 26, 2020 *Order Requesting Reply Comments*, in the above-captioned docket, and submit their reply comments on the proposed Commission Rules R8-51, filed by the Public Staff of the North Carolina Utilities Commission ("Public Staff"), North Carolina Sustainable Energy Association ("NCSEA"), the Environmental Defense Fund ("EDF"), the North Carolina Attorney General's Office ("AGO"), and Mission:data Coalition ("Mission:data").

As discussed in more detail herein, the Companies endorse a Commission Rule that governs access to their customers' nonpublic data that:

- Provides customers with control of their data;
- Provides the utilities subject to the Rule with clear, unambiguous terms to foster and promote ready compliance; and
- Does not impose additional costs and burdens on customers that outweigh any benefits to customers.

With limited exceptions discussed herein, the Companies respectfully submit that the Public Staff's proposed Rule R8-51 best meets those goals.

**A. Introduction**

The Companies recognize that with smart meters and greater digitization of electric utility services, the clarifying, expanding, and fortifying of existing Commission Rule R8-51 is vital. To that end, with limited exceptions, the Companies support the Public Staff's proposed revisions to Commission Rule R8-51. The Companies note that the proposed Rules of the Public Staff, the AGO, and Mission:Data are consistent with respect to certain critical concepts. For example, the proposed Rules stress the necessity of a customer's consent to disclosure of its data, expressly provide some limited protection to the utility at the Commission from third parties that might misuse customer data after receiving it from the utility, and contrast and clarify the difference between a utility's necessary usage of customer data to provide regulated, electric services to its customers and the disclosure of customer data to "third parties" for activities that are not regulated by the Commission. *Cf.* AGO's Rule R8-51(d)(1) and Public Staff's Rule R8-51(b); AGO's Rule R8-51(d)(6) and Public Staff's Rule R8-51(c).

The Public Staff's proposed Rule R8-51, however, strikes the necessary balance between protecting customers' nonpublic data and implementing a workable and efficient process for compliance with that Rule. The Companies have maintained and protected nonpublic customer information since prior to the 2012 merger of Duke Energy Corporation and Progress Energy, Inc. in Docket Nos. E-2, Sub 998 and E-7, Sub 986 ("Merger"), as approved by the Commission in the *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, issued on July 2, 2012 ("Merger Order"). In that Merger Order, the Commission approved a comprehensive framework of data protection, involving procedures for disclosure of data and self-reporting for violations of those procedures, as part of the Companies' Code of Conduct ("Code").[1] In the Merger Order, the Commission also directed that the Companies establish a Compliance officer and conduct annual trainings of their employees and the employees of their service companies on the provisions of the Code. *See* Regulatory Condition Nos. 14.1-14.4.[2]

The AGO's comment that the Code is primarily aimed at commercial competition between the Companies and their affiliates is accurate; the Companies agree that the Code's restrictions and limitations on the disclosure of nonpublic customer information were not intended for the singular purpose of protecting nonpublic customer data from disclosure. This does not mean the procedures that the Companies have developed to comply with the Code, however, have no value in the context of this Rulemaking. To the contrary, the Companies' Compliance team works to administer both the Commission-approved Code and the Companies' privacy policy, found online at https://www.duke-energy.com/Legal/Privacy. A review this policy shows that Duke Energy fully informs its customers about the customer information it collects and maintains and how that information is treated. The procedures and trainings that the Companies have established as a result of the Code restrictions and their privacy policies have already created a robust framework to protect nonpublic customer data from unauthorized or inappropriate

[1] This is not to say that DEC and DEP were not subject to Codes of Conduct that protected customers' data prior to the 2012 Merger; they were, and the Codes of Conduct were similar to the current one. However, the Companies will refer to the Code of Conduct approved in the 2012 Merger for ease of reference in these Reply Comments.

[2] The most recent Commission order containing these Regulatory Conditions is the *Order Granting Motion to Amend Regulatory Conditions*, Docket Nos. E-2, Sub 1095A, E-7, Sub 1100A, and G-9, Sub 682A, issued Aug. 24, 2018 ("2018 Reg. Con. Order").

disclosure to third parties by the Companies, their agents, and their affiliates, while also giving customers the ability to authorize disclosure to other third parties.[3] Incorporating some of this pre-existing framework into this Rule fosters the Companies' compliance and serves customers' interests.

As the Companies diligently work to protect customers' nonpublic data from unauthorized or inappropriate disclosure, they also agree that allowing customers greater access to their own energy usage data empowers them to make informed decisions about their energy usage. To that end, as the Companies noted in their initial comments, they are currently implementing customer access functionality like the access provided by "Green Button: Download my Data" current functionality. DEC and DEP customers with smart meters are already able to view and download their electric usage data from the Companies' websites in a standardized format. These customers can view and download their hourly and daily electric usage information from the online customer portal and through mid-cycle notifications with the Usage Alerts program.

As discussed later herein, the Companies do not support the entirety of the Public Staff's proposed Rule R8-51 because it imposes costs on customers that outweigh the benefits; however, the Companies agree that the Public Staff's proposed Rule generally provides for electric public utilities to maintain nonpublic customer data as necessary and to provide access to that data without imposing additional complexities or unnecessary costs on ratepayers. Moreover, as previously stated, the Companies appreciate the willingness of the Public Staff to adapt and enhance the pre-existing framework for

[3] With respect to disclosure of nonpublic Customer data to the Companies' affiliates or nonpublic utility operations, the Commission has approved a "script" found in Attachment A of the Code to obtain customer authorization. For disclosure to other non-affiliated third parties, the Companies use other forms for customer authorization.

protecting Customer data. Expanding this existing framework minimizes costs to customers and facilitates compliance because the Companies already have in place compliance procedures and practices in operating with their affiliates as well as outside contractors and vendors that they can build on if the Commission approves the Public Staff's proposed Rule. In contrast, as discussed in more detail below, the AGO's and Mission:Data's proposed Rules, which are each in excess of 12 pages, are generally more complex and, thus, more complicated to administer or to explain to customers. The Companies' Reply Comments discuss in Section B why they support the Public Staff's Proposed Rule (except for Subsections (d), (g), and (h) that go into effect on January 1, 2022). In Section C, the Companies' Reply Comments describe how the Public Staff's Rule conforms to the Commission's authority under Chapter 62 of the General Statutes. In Section D, the Companies discuss the Public Staff's proposed subsections (d), (g), and (h) and similar proposals by the intervenors, which the relate to the provision of Customer data to third parties through direct, electronic methods.

## B. The Public Staff's Proposed Rule R8-51 Protects Customers' Nonpublic Data and Privacy in Clear and Easy to Understand Terms that Expand on the Commission's History and Procedures in Protecting Nonpublic Customer Data.

The Public Staff's Proposed Definitions are consistent with Chapter 62 of the North Carolina General Statutes and Commission Precedent.

The Companies generally agree with the Public Staff's proposed definitions of terms to be used in Rule R8-51. The definition of "Customer Data" is comprehensive and consistent with, although not identical to, the definition of "Customer Information" that the Commission approved in the Companies' Code. To illustrate, the Companies' Code defines "Customer Information" as

> nonpublic information or data specific to a Customer or to a group of Customers, including but not limited to, electricity consumption, . . . load profile, billing history or credit history that has been obtained or compiled by DEC, [and] DEP, . . . in connection with the supplying of *Electric Services* . . . to that Customer or group of Customers.[4]

Code, Sec. I (Emphasis added.).[5] "*Electric Services*" is further defined as "Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers." Code, Sec. I. The Public Staff's definition incorporates that definition and provides additional clarifying detail, such as that Customer data includes a customer's participation in regulated utility programs, like energy efficiency programs. Public Staff's Rule R8-51(a)(2) (i-iv).

The Public Staff's proposed Rule also crucially and clearly defines the activities and parties that may be involved in the regulated utility's potential disclosure of Customer data. First, the Public Staff defines "Nonpublic utility operations" as "all business enterprises engaged in by a utility that is not regulated by the Commission or otherwise subject to public utility regulation at a state or federal level." Public Staff's Rule R8-51(a)(3). This definition is consistent with the definition that the Commission approved in the Companies' Code and in N.C. Gen. Stat. § 62-2(3)3. N.C. Gen. Stat. 62-(3)23 exempts enterprises that are not public utilities from Commission regulation, even if a "person" conducting a public utility also conducts that non-regulated enterprise. In other words,

[4] The Companies have removed the references to Natural Gas Services related to Piedmont Natural Gas Company included in this definition for the Commission's convenience.
[5] Although this provision of the Code can be found in several Commission orders, including the Merger Order, the most recently-approved version of the Code was in 2018 Reg. Con. Order.

nonpublic utility operations are not subject to the provisions of Chapter 62, which establishes the Commission's jurisdiction over the Companies' public utility operations. The Public Staff also defines "third party" to be any person that is not the customer and clarifies that it does not include an agent of the customer (such as an adult child acting on behalf of an elderly parent), and a contracted agent for the utility. Additionally, "third party" includes both nonpublic utility operations and affiliates of the utility. This definition is likewise consistent with the Commission's distinctions in the Code and the Companies' practices that result from the Code's provisions.[6] Finally, the Public Staff, further defines "aggregated data," "personal information" and "unique identifier" in simple, easy to understand terms. In sum, the definitions included in the Public Staff's proposed Rule collectively protect Customer Data and help guide how appropriate or authorized access to may be allowed.

In contrast, the AGO's and Mission:Data's proposed Definitions appear to be more complex and, therefore, may be more difficult for customers and utility employees to understand. For example, the AGO's rule includes at least four different categories of data in addition to aggregated data such as: (i) covered information; (ii) standard customer data, (iii) "unshareable personal data" and (iv) "usage data." Distinguishing between these various types of data may be confusing to customers and difficult to administer by the Companies' employees. Accordingly, the Companies respectfully believe that the Public Staff's distinctions between "personal information" and "Customer data" in its proposed

[6] *See* Code at Sec. III(A)(2)(a)-(f). (In these provisions, the Commission approved essentially treating the nonpublic utility operations and affiliates of DEC and DEP as similarly situated to non-affiliated third parties for purposes of disclosing nonpublic Customer data.)

Rule are more easily understood and administered by utility employees, while still providing no less protection to customers' privacy.

The AGO and Mission:Data's proposed Rules also introduce new terms, such as "primary purposes" for definition. Primary purposes, however, appear to mirror "Electric Services" as included by the Public Staff and defined in the Code. "Secondary purpose or use" appears to correspond to the Public Staff's definition of "nonpublic utility operations," a well-established term that the Commission has employed since at least 2006 to refer to those activities carried out by the utility that are not subject to the Commission's jurisdiction under Chapter 62.[7] The Companies respectfully submit that the Definitions sections of the Public Staff's, Mission:Data's and AGO's proposed Rules appear similar in concept; however, the Public Staff's version uses less complex and less novel terms that reflect prior Commission orders.[8] The Companies' personnel are more accustomed to these terms in the context of their compliance efforts, and therefore can strengthen pre-existing compliance policies to conform to this Rule.

Customer Consent

The Companies continually work to maintain a culture of protecting nonpublic Customer data. Obtaining customer authorization prior to the disclosure of nonpublic Customer data is central to those efforts. In only limited circumstances, discussed later herein, do the Companies disclose nonpublic Customer data without customer authorization to do so. In short, as outlined in their Code, the Companies do not disclose

[7] *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket No. E-7, Sub 795, Attachment B (Code of Conduct) at p. 2, issued March 6, 2006.
[8] Merger Order, Code at Sec. I*; Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, issued Sept. 29, 2016.

nonpublic Customer Information to: (i) non-affiliated third parties, (ii) affiliates, or (iii) nonpublic utility operations without customer authorization to do so.[9]

The Companies support the Public Staff's proposed Rule R8-51(b)-(c) and (g) – (k) (except for the amendments to those subsections that the Public Staff propose to go into effect on January 1, 2022). These subsections clarify that the utilities may use Customer data for regulated purposes under N.C. Gen. Stat . § 62-3(23), further underscoring that the utilities may not disclose Customer data to their nonpublic utility operations or an affiliate without customer authorization. Public Staff's Rule R8-51(b).[10] The Public Staff's Proposed Rule also provides that the utilities must inform the Commission of any disclosure of the customer's data without the customer's consent. *Id*. This is consistent with the Code's requirement that the Companies report any inappropriate disclosure of DEC or DEP Customer data, describing the circumstances of the disclosure, the Customer data disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences, to the Commission. Code Sec. III(A)(2)(k). The Companies have filed these reports in Docket Nos. E-7, Sub 986C, E-7, Sub 1100C and E-2, Sub 1095C. In short, the provisions in the Public Staff's Proposed Rule fortify and expand on the Companies' Code's requirements for customer authorization for

[9] Code, Sec. III(A)(2)(b); *see also* Code Sec. III(A)(1) (DEC, DEP and other affiliates shall operate independently of each other and the Companies' nonpublic utility operations shall maintain separate records from public utility operations).

[10] The AGO's initial comments state that the Code does not appear to require a utility to obtain consent to use customer information for "secondary purposes." AGO Comments at 26. Although the Code does not use the term "secondary purposes," it does unequivocally provide that the Companies may not disclose Customer Information (or as used in this context "Customer data") without customer authorization to nonpublic utility operations, which are business operations not related to the electric utility service that the Commission regulates. To the extent that prohibition was not clear in the Code (which the Companies do not concede), the Companies believe that the Public Staff's proposed Rule R8-51 fully accomplishes and explains this prohibition in terms that the Commission has previously used in the merger dockets and that are understandable to the affected utilities.

disclosure of nonpublic Customer data, without imposing additional complexity on the Companies' compliance efforts. Although the Companies support these subsections, they discuss certain aspects of them in more detail below.

1. Consent Form or Process

The Public Staff's proposed Rule requires that a utility shall not disclose Customer data to a third party unless the customer submits a paper or electronically signed consent form. The Public Staff's proposed Rule also provides that the contents of the electronic consent form must follow the format of a Commission-prescribed form, but does not require Commission approval of the form. This provides the customers with protection, but, by not requiring the Commission to approve the actual form itself, allows for less cumbersome administration of the process because it allows the Companies to compose their own forms, consistent with the Rules, but does not compel them to submit them to a Commission approval process for any subsequent alterations, material or not, to the form.

2. Limited Disclosure to Utility Contractors Working on Behalf of the Companies

The Public Staff's proposed Rule also accurately reflects how the Companies operate with outside contractors or Duke Energy affiliates who provide services to the Companies or to the Companies' customers on behalf of the regulated utility. Under the Public Staff's Rule R8-51(c), "a utility may, . . . in its provision of regulated utility service, disclose Customer data to a third party, consistent with the utility's most recently approved Commission Code of Conduct, to the extent necessary for the third party to provide goods or services to the utility and upon written agreement by that third party to protect the confidentiality of such Customer data." This provision is consistent with the Commission's

2011 approval of an amendment to Dominion's North Carolina Code of Conduct, where Dominion requested to use non-affiliated vendors and consultants in implementing, evaluating, measuring, and verifying Dominion's energy efficiency and demand-side management programs. *Order Approving Code of Conduct Amendment*, Docket No. E-22, Sub 380A, issued May 10, 2011 at p. 2. The Public Staff's Rule additionally provides a workable method for Duke Energy affiliates, such as the Duke Energy service company, Duke Energy Business Services ("DEBS"), to provide services, such as legal representation, to the Companies. Under the Public Staff's proposed Rule, DEBS, other affiliates and non-affiliated third parties will have limited access to the Customer Information necessary to provide services to the regulated utility, while protecting that Customer Information from any additional disclosure.[11] This process has been in place for the Companies since at least 2012. The Companies require their outside contractors and their affiliates to maintain the confidentiality of Customer data needed to perform the service.

The AGO's and Misson:Data's proposed Rule also appears to allow for the disclosure of Customer data to "utility contractors" in certain circumstances, but imposes limits on that disclosure that both may harm customers and impede effective administration. For example, the AGO's and Mission:Data's proposed Rule states that utilities are always prohibited from providing "unshareable personal data to any other party other than the customer." AGO's Proposed Rule R8-51(d)(9). "Unshareable" personal data includes, for example, credit reporting information, health information, or the network

[11] The Companies' Code imposes restrictions on DEBS' use of DEC's and DEP's nonpublic Customer data that protect Customer data from inappropriate disclosure and complement the Public Staff's proposed Rule R8-51.

or internet protocol address of the customer. As noted, the Companies treat this type of information currently as nonpublic "Customer Information" under their Code and would continue to treat it as nonpublic Customer data or personal information under the Public Staff's proposed Rule R8-51, if it is approved. The Companies, however, typically after receiving customer authorization to do so, have on occasion shared limited health information (such as a customer's requirements for electric medical devices) about their customers with a social assistance agency (or the Public Staff) to the extent necessary to help obtain assistance for those customers. Under this provision of the AGO's and Mission:Data's Proposed Rule, it appears that the Companies would never be allowed to share such information with any third party - Public Staff or otherwise - even with customer authorization. Additionally, as noted above, the Companies' attorneys work for a third-party affiliate that provides services to the utility under a contract with that utility —DEBS. Therefore, a blanket prohibition on sharing such information may impede the Companies' attorneys from defending the Companies against complaints at the Commission, as they would not have access to certain potentially relevant information. If a customer had an excellent credit history with one Duke affiliate, that affiliate would be unable to share that credit history with another affiliate, if the customer wanted to initiate service in the affiliate's service territory. For example, customers may not understand why they must undergo a separate and new credit check to establish new service in the Companies' North Carolina service territories when they have had an excellent payment record with the Companies' affiliate, Duke Energy Florida, LLC. Under the AGO's proposed Rule, it is not clear that Duke Energy Florida, LLC could validate a customer's good payment record or credit history for DEC or DEP.[12] Finally, as noted above, the Companies have engaged outside contractors to assist in the evaluation, measurement, and verification of energy efficiency and demand-side management measures. Accordingly, it appears in these instances listed above that the AGO's and Mission:Data's proposed Rule would never allow for the sharing of potentially relevant information (notwithstanding the customer's authorization), which works to the detriment of customers seeking assistance and participating in energy efficiency and demand-side management programs and the Companies' ability to receive necessary services. Therefore, the Public Staff's proposed Rule better protects customers in a workable, straightforward manner.

## C. The Public Staff's Proposed Rule R8-51 Comports with the Commission's Authority to Protect Customer Data and Regulate Electric Utilities.

As noted above, with limited exceptions, the Companies support the Public Staff's proposed R8-51 as a comprehensive framework to protect Customer data while providing the utilities the circumstances under which they may allow customers and third parties access to nonpublic Customer data. The Companies note that the AGO's and Mission:Data's proposed Rule R8-51(h) and (k)-(u) impose requirements that are: (i) beyond the Commission's authority under Chapter 62 and potentially superfluous because of requirements already in place.

### 1. Rule R8-51 does not require its own Complaint Procedure in Addition to the Commission's Complaint Procedure outlined in Rule R1-9.

[12] The Companies have shared with the Public Staff that under their Customer Connect platform, which they are currently implementing, they will expressly seek authorization to use a customer's good credit history with one Duke affiliate to establish credit for that customer in other Duke Energy affiliate's service territory. The Companies will not, however, use customer's poor credit history with a Duke Energy affiliate against the customer in any circumstances.

The AGO's proposed Rule provides that complaints under this Rule shall be treated as Complaints under R1-9. Commission Rule R1-9 provides a sufficient and well-established procedure for customers to raise complaints against public utilities. The AGO's and Mission:Data's proposed Rule further provides, however, that "If a utility has a reasonable suspicion that an authorized third party has engaged in conduct rendering it ineligible to access information under [Rule R8-51], the utility shall expeditiously inform the Commission and the Public Staff of any information regarding possible ineligibility." The proposed Rule does not explain how this report to the Public Staff or the Commission is helpful to either, and, indeed, the Commission has stated that its complaint jurisdiction does not extend to third parties that are not public utilities:

> As stated in G.S. 62-73 and G.S. 62-74, the subject matter of any complaint may only relate to "any act or thing done or omitted to be done by any public utility." This subject matter jurisdiction does not include acts done by persons . . . that are not a public utility. Subject matter jurisdiction cannot be agreed upon by the parties, nor waived, as it may be raised as a defense at any time. Time Warner Entertainment Advance/Newhouse Partnership v. Town of Landis, N.C. App., 747 S.E.2d 601 (2013). Therefore, the Commission does not have jurisdiction over the subject matter of a potential complaint by Duke[.]

*Order on Jurisdiction and Dismissal of Complaint*, Docket No. E-7, Sub 1038, issued March 5, 2014 (DEC and the City of Greensboro had agreed that DEC could file a complaint against customers living in Greensboro that refused to allow DEC to carry out its tree trimming obligations to provide electric utility service as approved by the Commission, but the Commission concluded such an agreement was outside the Commissions' jurisdiction) (Emphasis in the original). Therefore, it is unclear what authority the Public Staff and the Commission have over these reported third parties under this provision of the AGO's and Mission:Data's R8-51(h)(2) or (3).

The proposal above appears to link the utilities' obligations to report this type of information to the Commission and Public Staff to the Commission's confirmation that a third party is or has become ineligible for receipt of nonpublic Customer data. It does not explain how the Commission would make such a determination, however, or how the Public Staff would police such matters with information provided by the utility. Moreover, it is unclear with respect to the utility's ability to contract with third parties regarding the provision of nonpublic Customer data. For example, the AGO's proposed Rule R8-51(h)(2) provides that if a utility believes it is necessary to terminate an authorized third party's access to Customer data, the utility shall file a request to do so. Rule R8-51(h)(4) provides that the Commission shall allow the utility to refrain from providing Customer data to that third party. Neither subsection, however, explains how the Commission would make such a determination or provides a time frame for such a determination to be made. Therefore, the Companies respectfully request that the Commission decline to adopt the AGO's and Mission:Data's proposed Rule R8-51 with respect to Complaints.

2. <u>The Companies are already Subject to Reporting and Auditing Requirements Related to their Maintenance of Nonpublic Customer Data; therefore, Additional Requirements are Unnecessary and Impose Unnecessary Costs on Customers.</u>

Mission:Data's proposed R8-51(k) and (q) impose reporting requirements on the utilities with respect to the provision of Customer data. According to the AGO's Rule R8-51(k)(1), for example, the utilities shall report the Commission the number of demands received for the disclosure of Customer data and the number of customers whose records were disclosed. Under the AGO's Rule R8-51(p)(3), the utility shall file an annual report with the Commission that notifies it of all the security breaches (which appears undefined) within the calendar year affecting the covered information directly or indirectly through one of its contractors. The proposed rule does not provide, however, what the Commission would do with the information contained in these reports or how these reports would benefit customers. The AGO's and Mission:Data's proposed Rule also requires the utilities to be accountable for complying with the requirements here and imposes additional auditing and reporting requirements upon them.

The Companies are always accountable for complying with the requirements of the Commissions' Rules and orders and are always willing to provide information to the Public Staff and Commission regarding how they maintain, protect, and provide access to Customer data. The Commission has already provided that the Companies shall report to the Commission any inappropriate disclosure of nonpublic Customer data to a non-affiliated third party, an affiliate or to nonpublic utility operations in the Code.[13] In the past, because of the Code, the Companies have notified the Public Staff when an inappropriate disclosure of nonpublic Customer data has occurred prior to filing the self-report. Additionally, the Companies' Regulatory Condition No. 5.1 provides unequivocally that the Commission and the Public Staff shall continue to have access to the books and records of the Companies, the Companies' affiliates and nonpublic utility operations. Accordingly, the reporting and auditing requirements included in the AGO's and Mission:Data's proposed Rule R8-51 are not necessary because of the Commission directives already in place. Additional reporting requirements imposed on the Companies will result in additional costs being imposed on customers without clearly providing any additional benefit. For this reason, the Companies respectfully request that the

[13] Code at Sec. III(A)(2)(k).

Commission decline to adopt the auditing and reporting requirements in the AGO's and Mission:Data's proposals in this context.

**D. <u>The Companies Currently Provide for Customers to Download Their Energy Usage Data and Provide it to Third Parties.</u>**

As noted in their initial comments, the Companies oppose the Public Staff's proposed revisions to Commission Rule R8-51(d), (g) and (h), which mandate a "Green Button Connect" functionality where third parties, other than the customer, may access customer energy usage data electronically through the North American Energy Standard's Board ("NAESB") Reg. 21, the Energy Services Provider Interfact ("ESPI") or a Commission-approved electronic machine-readable format. Other intervenors, such as the AGO and Mission:Data, have espoused the same position and have included similar requirements in their proposed Rules, although unlike the Public Staff's proposal, these proposed requirements appear to be effective immediately. Although the Companies fully support allowing customers access to their energy usage data to better inform their energy usage in the future, the Companies oppose these proposed mandates because, by authorizing third parties to have ready access to customers' energy usage data, they impose costs on customers that outweigh any benefit customers may obtain.

As noted, the Companies are implementing Customer Connect, a program designed to bring new capabilities to the Companies' customers. Delivering Customer Connect is foundational to transforming the Companies' customers' experience. To allow for successful testing, training, conversion and implementation of the core solution, in March 2020 the Companies stopped ingesting changes to many IT systems and business applications. Although the Companies recently updated the Commission to indicate that they will accelerate the program timeline to deliver the new customer service platform five months earlier than originally reported and planned for DEP, the new Customer Connect deployment date for DEP is November 2021. The time frame remains April 2021 for DEC. Even with this change in the time frame for DEP, the Companies have already invested resources in delivering these new customer capabilities. Additionally, if the Commission approves the Public Staff's proposed revisions, the Companies note that they could not begin such a project until late 2022 or early 2023, after full implementation and stabilization of Customer Connect. Moreover, they already have a process to field third-party data requests for customer usage and billing information, and they are prepared to comply with all other provisions of the Public Staff's proposed Rule R8-51.

This proposal also appears to potentially place on the Companies considerable responsibility (and costs) in implementing this capability for third parties. *See* e.g. the AGO's proposed R8-51(f) (2)-(9) (describing, among other things, the utilities' obligations with respect to providing third parties access to Customer data through electronic means). Furthermore, the Companies would be required to secure the transfer of this data to third parties. The numerous obligations in the AGO's proposed Rule create administrative burdens and would likely increase the cost of compliance to provide third parties direct electronic access to Customer data that they may already request through the existing processes.

Notably, the Companies are already providing Customer data access functionality to their customers like the access currently provided by Green Button: Download my Data functionality. Customers with smart meters are already able to view and download their electric usage data from the Companies' websites in a standardized format. These customers can view and download their hourly and daily electric usage information from the online customer portal. Additionally, the following table shows that from February 26, 2020 until July 14, 2020, relatively few of the Companies' North Carolina customers accessing their accounts online chose to use this feature:

| Jurisdiction | February 2, 2020 through July 14, 2020 | "Download My Data' Sessions | % of Sessions using Feature |
|---|---|---|---|
| DEC NC | 2,591,840 | 2,782 | 0.11% |
| DEP NC | 1,895,693 | 1,766 | 0.09% |

Because their customers have demonstrated minimal demand for this information themselves, the Companies are reluctant to invest the required additional resources and time adding functionalities to their Customer Connect platforms that are not responsive to customer needs and demands and that will benefit third parties. There would be operational implications including ongoing administration costs to support the scaled collection and management of customer consent, the cost to assemble requirements and build, test, and maintain the capability annually and support required within customer services to manage customer inquiries related to the capability. Based on the foregoing, and contrary to EDF's initial comments, it would be "costly and duplicative" to adopt the "Green Button Connect My Data" as urged by the Public Staff and other intervenors.[14] As such, the Companies do not believe that the Commission should mandate this investment of resources and time to deliver a product that customers would have to pay for, when there has been no demonstration of customer demand.

[14] EDF Initial Comments at 3.

Accordingly, the Companies respectfully request that the Commission approve the Public Staff's proposed Rule R8-51, excepting the Public Staff's proposals that go into effect in the 2021.

Respectfully submitted this the 17th day of July 2020.

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DUKE ENERGY PROGRESS, LLC

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PLACE: Dobbs Building
Raleigh, North Carolina

DATE: Thursday, March 15, 2018

TIME: 1:58 p.m. - 6:06 p.m.

DOCKET NO.: E-7, Sub 1146



BEFORE: Chairman Edward S. Finley, Jr., Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

DUKE ENERGY CAROLINAS, LLC

Application for Adjustment of Rates and Charges
Applicable to Electric Utility Service
in North Carolina.

VOLUME: 18

Noteworthy
Reporting Services, LLC

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TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

No. 1 were admitted into evidence.)

CHAIRMAN FINLEY: And Mr. Schneider, I believe, is the next witness.

MR. ROBINSON: Mr. Chairman, we are actually going to call Retha Hunsicker.

CHAIRMAN FINLEY: All right.

MR. ROBINSON: Mr. Chairman, as Ms. Hunsicker is coming up, in the interest of time, we are prepared to forego the reading of Ms. Hunsicker's summary of her testimony if the Commission wishes.

CHAIRMAN FINLEY: It's up to you.

RETHA HUNSICKER,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION BY MR. ROBINSON:

Q. Good afternoon.

A. Good afternoon.

Q. Ms. Hunsicker, please state your full name and business address.

A. My full name is Retha Hunsicker, and business address is 400 South Tryon Street, Charlotte, North Carolina.

Q. By whom are you employed and in what

capacity?

A. I'm employed by Duke Energy Business Services, and my capacity is vice president customer connect solutions.

Q. And did you cause to be prefiled in this docket prefiled direct testimony consisting of 12 pages and Hunsicker Exhibit 1 consisting of one page?

A. Yes.

Q. Do you have any changes or corrections to your direct testimony?

A. No, I do not.

Q. And if I asked you the same questions today, would your answers be the same?

A. Yes.

Q. Ms. Hunsicker, did you also cause to be filed in this docket prefiled rebuttal testimony consisting of 15 pages?

A. Yes.

Q. Do you have any changes or corrections to that testimony?

A. No.

Q. If I asked you the same questions today, would your answers be the same?

A. Yes, they would.

MR. ROBINSON: Mr. Chairman, at this time, I move that the prefiled direct and rebuttal testimonies of Witness Hunsicker be copied into the record as if given orally from the stand, and that her Hunsicker Exhibit 1 be marked for identification.

CHAIRMAN FINLEY: Ms. Hunsicker's direct testimony of 12 pages of August 25, 2017, is copied into the record as though given orally from the stand, and one exhibit is marked for identification as premarked in the filing, and her rebuttal testimony of 15 pages of February 6, 2018, is copied into the record as though given orally from the stand.

(Whereupon, Hunsicker Exhibit No. 1 was identified as marked when prefiled.)

(Whereupon, the prefiled direct testimony and prefiled rebuttal testimony of Retha Hunsicker was copied into the record as if given orally from the stand.)

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-7, SUB 1146**

| | | |
|---|---|---|
| In the Matter of: | ) | |
| | ) | **DIRECT TESTIMONY OF** |
| Application of Duke Energy Carolinas, LLC | ) | **RETHA HUNSICKER** |
| For Adjustment of Rates and Charges | ) | **FOR DUKE ENERGY** |
| Applicable to Electric Service in North | ) | **CAROLINAS, LLC** |
| Carolina | ) | |

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Retha Hunsicker and my business address is 400 South Tryon Street, Charlotte, North Carolina.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Business Services, LLC as Vice President Customer Connect, Customer Operations.

**Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.**

A. I hold a Bachelor of Science degree in Business Administration from Indiana Wesleyan University.

**Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.**

A. Since 1981, I have been employed by, and worked for, companies under what is now Duke Energy Corporation ("Duke Energy"). I began my career with Public Service Indiana, the predecessor to Duke Energy Indiana, Inc. as an Accounting Assistant. Since then I have held positions with increasing levels of responsibility. More recently, over the last ten years, I have held several roles including Director, Business Standards and Integration and General Manager, Smart Energy Systems and Processes. In 2012, I took the position of Regional Director, Customer Services, leading our Midwest contact centers before promoting to Vice President, Customer Contact Operations, in 2013. I assumed my current role as Vice President Customer Connect, Customer Operations in 2015.

**Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS VICE PRESIDENT CUSTOMER CONNECT, CUSTOMER OPERATIONS.**

A. I have executive management oversight for the Customer Information System ("CIS") consolidation project (known as Customer Connect), including the planning, execution and deployment. This program is responsible for the successful deployment of a new customer platform that will enable the functional capabilities needed to meet our strategic purpose of powering the lives of our customers by transforming how we serve them.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

A. While I have not appeared in person before the Commission, I submitted direct testimony in Duke Energy Progress's ("DE Progress") ongoing rate case in Docket E-2, Sub 1142, which is scheduled for hearings in November of this year. **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to discuss the CIS used by Duke Energy Carolinas LLC ("DE Carolinas" or the "Company") and explain why it is necessary to convert that CIS into a modern customer service platform.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. DE Carolinas' CIS systems are in dire need of modernization. We have extracted all of the value we can from our current system, which is over twenty years old. Our business and our customers' needs are very different than they were when the original system was constructed, and have moved past the point where modular "bolt on" systems or modular upgrades are effective. In my testimony, I describe the Company's plans, the anticipated costs and the revenue requirement we are seeking in this case to support this major --and necessary--technological upgrade.

Q. **WAS HUNSICKER EXHIBIT 1 PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?**

A. Yes, it was.

Q. **ARE YOU FAMILIAR WITH THE CIS OF DE CAROLINAS?**

A. Yes.

Q. **PLEASE EXPLAIN THE PURPOSE OF A CIS.**

A. A CIS manages the billing, accounts receivable, and rates for the Company and is the central repository for all customer information. It links the consumption and metering process to payments, collections, and other downstream processes including additional work order requests such as service connections and disconnections, outages and trouble requests. A CIS manages customer profiles and integration of data to provide a holistic view of the customer and should enable expected customer capabilities.

Q. **PLEASE PROVIDE A GENERAL DESCRIPTION OF THE COMPANY'S EXISTING CIS.**

A. The current CIS for DE Carolinas ("DEC") is a mainframe solution that was developed beginning in 1995, and was put in service in 1997. The current CIS was designed as a premise-based system. That is, it was developed to communicate with the meter attached to a premise, without regard to who may be consuming the services provided through the meter or how they may be consuming those services.

Although state-of-the-art twenty years ago, the current CIS was not designed to efficiently support new capabilities, including personalized experiences for our customers, advanced pricing structures and billing options, and tools for customers to better manage their energy consumption. We have added functions to the legacy system to try to meet business needs. But as we add newer technologies to the legacy system, the complexity continues to increase, thereby leading to more system disruptions and longer time to recover from outages. In some cases, the business has started looking for other options to meet needs, resulting in disjointed solutions and causing us to leverage multiple vendors. Moreover, certain functions are not compatible with the current CIS as further discussed below.

**Q. IS THE CURRENT SYSTEM A FULLY AUTOMATED SYSTEM?**

A. No. There are inherent design limitations in this decades-old system and it is not possible to incorporate modifications that enable the automation of certain functions, such as complex billing.

**Q. PLEASE EXPLAIN HOW COMPLEX BILLING IS COMPLETED UNDER THE COMPANY'S CIS.**

A. Because of the existing limitations with the current CIS, complex billing functions must be done manually. Additionally, the system is not designed to enable automated billing for customers having distributed generation with net metering. Our current systems were not designed to produce a credit bill, so these customers receive bills containing charges that are calculated manually. These manual interventions are not desirable for a variety of reasons. Among such reasons is inefficiency. Additionally, as the number of customers having these billing arrangements increases, there is an understandable impact on the Company's ability to provide timely and accurate bills. And it must be accepted that injecting manual intervention into what should be an entirely automated process creates an opportunity for unintended consequences.

A good example is net metering. The current system is unable to handle even simple transactions for any customers who produce their own energy, whether they're large industrial customers or a residential customer with a solar array on the roof. Any account that takes advantage of net metering must be reconciled by hand, which is not only burdensome on the Company's staff but also introduces a point for errors to be made which further frustrate our customers. As net metering grows, we need a system that can handle that type of complex billing as products, service and interactions continue to develop within our industry.

**Q. ARE THERE ANY DEFICENCIES WITH DE CAROLINAS' CURRENT SYSTEM?**

A. Yes, and those system deficiencies affect our ability to serve our customers. For example, the current CIS does not enable ready access to account histories that can be important in non-pay situations or when a customer is seeking to relocate within the Duke Energy jurisdictions. Consequently, a long-standing customer with a history of consistently paying bills on time and in full could be required to pay a security deposit as a condition of receiving service in a new home; a situation that could be avoided with improved access to account histories. Assume that a DE Carolinas customer moves to a DE Progress jurisdiction. At present, the DE Carolinas customer service representative can only help stop service. They can't help establish new service, or transfer any deposits. Once service is stopped at one location, the customer would need to be transferred to another customer service representative at DE Progress who has no knowledge of the customer's history with DE Carolinas. They are going to ask for all of the same information the customer has already given the DE Carolinas representative, and they'll perform a new credit check, and take new deposits. Even for a new customer, establishing service, it can take a customer service representation over 25 screens to get all of the necessary information input. This affects the ease in which customers can establish service. These types of challenges exist on many fronts, including routine service interactions.

As I mentioned above, the current CIS is a premise-based system. Such a restrictive system prevents DE Carolinas from interacting with customers in a meaningful and continually relevant manner. For example, the current CIS does not enable the Company to identify a customer's preferred method of communication. Thus, a customer who consistently opts out of the interactive voice response ("IVR") in order to speak directly with a customer service representative must continue to go through, for them, irritating process to obtain answers or information related to their utility service. Additionally, much of our customer base favors more modern communication channels, where information is almost immediately available. The current CIS does not enable these customers to employ their preferred methods of communication.

**Q. CAN DE CAROLINAS SIMPLY RELY ON CONTINUED MODIFICATIONS OF THE EXISTING CIS?**

A. No. As a practical matter, the current limitations discussed above cannot be remedied with modifications. Continued investment to modify an antiquated technology platform is not practical or sustainable. CIS's, like any other software solution, are subject to obsolescence, and like other technology and software, must be made periodically to meet customer expectations.

DE Carolinas' current system must be replaced to provide a more stable platform, greater flexibility, ease of configuration and ability to offer more advanced rates and billing structures, as well as services to customers, than what is currently possible. The existing system, while state-of-the-art twenty years ago, has become cumbersome, difficult to update and limited in functionality compared to new systems that are currently available. Continued investment in an antiquated technology platform is neither practical nor sustainable, and would cost considerably more in the long run than replacing the system in its entirety. Customer information systems, just like any other software solution, periodically require replacement to deliver on capabilities required by business operations, and more importantly, customers.

**Q. PLEASE DISCUSS HOW A MODERN CIS WILL BENEFIT DE CAROLINAS CUSTOMERS.**

A. Through the consolidation of the older customer information systems into a new customer information system, DE Carolinas will be able to deliver a customer experience that will simplify, strengthen and advance our ability to serve our customers. Key customer benefits include the following:

- Universal, simplified processes for customers
- Focusing on our customers rather than our meters to provide personalized service and to show customers that the Company understands their needs and quickly addresses their concerns.
- Improvements to bill formats, helping customers more easily view and understand their bills
- Ability to quickly help customers, provide the best, most cost effective rate structure for them, and allow the company to more quickly introduce and integrate new rates, riders and programs to better serve customers' unique needs
- Flexibility and scale in leveraging Advanced Metering Infrastructure ("AMI") and providing customers alternative rates and enhanced basic services (pick your own due date, usage alerts, Prepaid Advantage, etc.)
- More opportunities for advanced pricing structures and billing options

**Q. WILL THE NEW SYSTEM ALLOW FOR MORE FLEXIBLE RATE DESIGN AND OTHER RATE OFFERINGS?**

A. Yes, DE Carolinas' system requires significant coding to implement new rates and pricing. The system changes tend to be complex, expensive, and time-consuming. Indeed, the system is so burdensome that the Company has consulted with outside vendors to manage billing for new rate structures. New modern customer information systems are much more configurable, reducing the amount of time to test and implement pricing changes and offerings. As referenced in Witness Pirro's testimony, metering installed for the majority of current customers does not provide the interval level data that is required to bill these innovative designs. Therefore, DE Carolinas has plans to upgrade meters, and the CIS we are implementing will support evolutions in rate designs for our customers.

**Q. HOW LONG WILL IT TAKE TO FULLY IMPLEMENT THE SYSTEM FOR DE CAROLINAS?**

A. The Customer Connect Program will begin analysis and design in January 2018, and is currently planned to be placed in service for DE Carolinas in 2022. During this phase, the following activities will be completed, among others: understanding current state processes and capabilities of the new system, documenting future state processes, identifying any capability gaps with the new system and evaluating options for addressing those gaps, identifying the technical objects to be designed and developed, and identifying detailed requirements in preparation for the design phase of the program.

**Q. WILL THERE BE ANY BENEFICIAL IMPROVEMENTS FOR CUSTOMERS PRIOR TO FULL DEPLOYMENT FOR DE CAROLINAS?**

A. Yes, the Company will be deploying new capabilities every year leading up to full deployment to improve our customer's experience. These capabilities include, among others:

- Expanded communication preferences
- Streamlined experience when calling a service representative or using the automated voice prompts
- More personalized and customer-centric service
- Universal, customer-friendly bill format

**Q. WHAT WILL BE DUKE ENERGY CAROLINAS' ESTIMATED COST FOR THE CIS IMPROVEMENTS?**

A. The estimated cost for DE Carolinas is $285 - $295 million, with approximately 50 percent reflecting the capital investment. Specifically for DE Carolinas North Carolina, the costs will be between $220 - $230 million as shown on Hunsicker Exhibit 1. The Company has executed fixed price contracts for the primary software (SAP), systems integration (Accenture) and change management professional services (EY), following an extensive request for proposal process conducted in 2016. The best and final offer that resulted from this process formed the basis of the program's cost estimate, and includes an estimate of the incremental Company labor needed to support the scope of the contracts.

**Q. WHAT AMOUNT OF THAT COST IS DE CAROLINAS PROPOSING IN THIS CASE?**

A. In her testimony, Witness McManeus describes a pro-forma adjustment that increases the test year operating and maintenance ("O&M") expenses associated with the project from $4.4 million to $15.1 million. This increased amount is the average expected annual O&M associated with the project over the next three years, from 2018 through 2020.

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-7, SUB 1146**

| | | |
|---|---|---|
| In the Matter of: | ) | |
| | ) | **REBUTTAL TESTIMONY OF** |
| Application of Duke Energy Carolinas, LLC | ) | **RETHA HUNSICKER** |
| For Adjustment of Rates and Charges | ) | **FOR DUKE ENERGY** |
| Applicable to Electric Service in North | ) | **CAROLINAS, LLC** |
| Carolina | ) | |

## I. WITNESS IDENTIFICATION AND QUALIFICATIONS

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Retha Hunsicker and my business address is 400 South Tryon Street, Charlotte, North Carolina.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Vice President, Customer Connect-Solutions.

**Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes. I pre-filed direct testimony in this case. My qualifications, professional experience, and current responsibilities are described in that testimony.

## II. PURPOSE AND OVERVIEW OF REBUTTAL TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?**

A. My rebuttal testimony will respond to: (1) the justification used by Public Staff witness Michelle Boswell in her testimony to support the Public Staff's recommended adjustment to remove the forecasted expenses Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") expects to incur during the 2018-2020 time frame related to the Customer Connect project ("Customer Connect")[1]; and (2) NCSEA witness Michael Murray and EDF witness Paul J. Alvarez's recommendation to utilize "Green Button" to

[1] Testimony of Michelle Boswell, pp. 32-33

provide usage information to third parties,[2] and witness Murray's recommendations to provide historic usage and current rate data to customers and third parties in a machine readable format, and to establish a "user-friendly" customer authorization process[3].

**Q. PLEASE PROVIDE AN OVERVIEW OF YOUR REBUTTAL TESTIMONY.**

A. In response to witness Boswell's recommendation to remove the 2018-2020 forecasted O&M of $10.7 million from the Company's requested revenue increase, I explain that the Company's request to recover the forecasted O&M is reasonable and aligns with new functionality that will be in-service and providing benefits to customers every year of the project, beginning in 2018. In response to witnesses Murray and Alvarez, I explain the Company's position as it relates to providing customer information to third parties.

## ADJUSTMENT TO CUSTOMER CONNECT

**Q. PLEASE DESCRIBE WITNESS BOSWELL'S RECOMMENDATION REGARDING CUSTOMER CONNECT.**

A. Witness Boswell's testimony recommends an adjustment to remove the forecasted amounts the Company plans to spend between 2018 and the in-service date. In her testimony, witness Boswell's rationale for this adjustment is that the system is in the analytics stage, and more specifically, the Company

[2] Testimony of Michael Murray, pp. 15-46; Testimony of Paul J. Alvarez, pp. 39-41
[3] Testimony of Michael Murray, pp. 15-46.

is in the process of gathering customer data to build and develop the system. Witness Boswell also states that the system has not yet been placed in service and that full functionality for DEC is not expected until the summer of 2022.

**Q. DO YOU AGREE WITH THIS RECOMMENDATION?**

A. No. The Customer Connect program is far more advanced than witness Boswell suggests. Witness Boswell is correct that this is a long-lived program, but she is not correct about where we are in terms of our advancement of the program and our financial and contractual commitments to it. Moreover, to read witness Boswell's testimony, one would think she believes these costs should be capitalized to the program; however, that is not the way the accounting works as explained by Company witness Jane McManeus. The Company has only asked for the level of O&M necessary to deploy the capital for the program—we are not asking for the program or its costs to be placed into rate base at this time. Further, in order for the Company to recover these known and measurable O&M costs, they either need to be included in rates as we have asked, or, alternatively, set aside and capitalized to a regulatory asset to be recovered when the project comes on line as described by witness Boswell.

**Q. IS WITNESS BOSWELL CORRECT THAT CUSTOMERS NEED TO BE PROTECTED IN THIS CASE FROM FUNDING ESTIMATED COSTS FOR A SYSTEM THAT IS NOT YET FUNCTIONAL?**

A. No. First, as I fully describe later in my testimony, the Company will be delivering new capabilities to customers every year of the program beginning in 2018, so witness Boswell is incorrect that customers will not receive benefits until the system is fully installed. Second, the forecasted expenses for Customer Connect are known and measurable. Specifically, the Company has entered into fixed price contracts following an extensive request for proposal (RFP) process conducted in 2016. These contracts account for a significant portion of the overall cost of the program and cover the software, system integrator professional services, and change management and training professional services. These contracts also specify the amount of internal Duke Energy labor required to successfully complete the scope of each contract. The Company then added other costs required to complete the program for activities outside the scope of the contracts. Even the Public Staff's own witness, Jack Floyd, states in his testimony that he believes the amount of expenses included in this case related to the initial work on Customer Connect is reasonable.[4]

[4] Testimony of Jack Floyd, p. 36.

**Q. HOW WERE THE FORECASTED EXPENSES DERIVED?**

A. The best and final offers from the RFP process were used as the foundation for the forecast, which include the cost of the executed contracts as well as the amount of internal labor the Company is required to provide to complete the scope of the contracts. Specific costs to cover activities beyond the scope of the contracts but within the scope of the program, such as the effort to modify more than 100 interfacing systems, were added, leveraging established program estimating techniques and assumptions. These forecasted expenses were derived by members of the program team, each with extensive experience estimating and managing large-scale technology development programs similar to Customer Connect. The average O&M expense forecasted over the 2018-2020 period and attributable to DE Carolinas NC, which served as the basis for the incremental revenue requirement in this case, is approximately $15.1 million. That amount includes these components:

- Costs directly correlated with the fixed fee contracts, totaling approximately $3.8 million.
- As described above, the fixed fee contracts contain provisions requiring the Company to provide specific levels of labor to support execution of the work.. Costs for the incremental labor required to support the scope of the fixed fee contracts total approximately $1.2 million.
- The cost to develop each interface is within the scope of the fixed fee contract; however, the cost for any modifications required of the

interfacing systems is not within the scope of the fixed fee contract and represents a critical component of the overall program scope. Costs for the incremental labor required to modify the systems that the new Customer Connect solution will interface with total approximately $1.1 million.

- Costs for effective oversight, governance and quality management for the program, totaling $1 million.
- Costs for key leadership positions for the program, totaling approximately $0.8 million. These positions are filled, and their costs are known.
- Costs for cleanup of existing data in preparation for conversion into the new platform that were estimated following extensive benchmarking that occurred with other utilities that had recently completed a similar project. These costs cover the activities associated with mitigating data conversion risks and total approximately $0.6 million.
- The costs to ensure service to customers is not adversely impacted during the deployment of the new platform. These include items such as the cost to deliver training to end users of the new platform, incremental staffing required to maintain adequate customer service levels, and the stabilization period immediately following deployment. These costs total approximately $0.5 million.
- Costs to cover inflation and contingency that were forecasted using formal, established methods and were scrutinized and deemed appropriate

by an independent estimate review committee commissioned by the Company's project management center of excellence. These costs total approximately $4.7 million.

**Q. ALTHOUGH THIS IS A LONG-LIVED PROGRAM, IS WITNESS BOSWELL CORRECT THAT BENEFITS WILL NOT BE SEEN UNTIL FULL DEPLOYMENT?**

A. No. The Customer Connect program will deliver new capabilities to customers every year of the program beginning in 2018 and leading up to full deployment in 2021/2022. With this phased deployment approach, the Company will have system functionalities in-service and beneficial to customers at tiered stages throughout the implementation of the complete system, as referenced in Public Staff witness Floyd's testimony on page 33, lines 10-11. Accordingly, the Company's request to include the forecasted project spend from 2018-2020 in this proceeding aligns with the plan for multiple in-service dates throughout the project.

**Q. PLEASE ELABORATE.**

A. In 2018 ("Release 1" or "Analytics Release" and "Release 2" or "CRM Release"), the Company will incorporate advanced analytics capabilities that will allow it to better track the interactions and relevant touch points our customers are having with Duke Energy across multiple channels, such as web visits, Interactive Voice Response Unit (IVR), live voice calls, social media, etc. The Company will use that information to build a holistic customer profile, improving our ability to communicate with them and begin to engage with them in new ways. Per these releases, examples of new and/or improved capabilities that customers will experience include the following:

- Streamlined Customer Service experience -

  Leveraging insights from the holistic customer profile, the Company will be able to use the new platform to predict the intent of customers when they call, improving their experience with Duke Energy.

  In addition, the interaction tracking data, as referenced above, will be made available to the customer care specialists, who will leverage it for context into why the customer may be calling and to have a more informed and productive conversation with the customer.

- More timely, relevant and valuable communications -

  The customer data will also be leveraged to prioritize the types of information the customer prefers to receive and the methods of communication by which the customer prefers to receive the information, including via web, email or other channels to ensure it is timely, relevant and valuable to them.

- Improved communication campaigns -

  The Company will create improved communication campaigns to proactively provide important information about our customers' service with Duke Energy. Examples could include information about power outages, planned outages and vegetation management (*i.e.*, tree trimming).

These are just a few of the functions the Company intends to implement in 2018 to improve customers' everyday experience with Duke Energy.

In 2019 ("Release 3" or "Prepaid Release"), the Company will implement the Prepaid Release, which will implement core components of the complete meter-to-cash solution early for a subset of customers. With this release, the Company will be able to offer new or existing products and services on a prepaid basis to customers, providing them with more choice, control, and convenience in how they do business with us.

In early 2020 ("Release 4" or "Universal Bill"), the Company will introduce a universal bill format to help customers more easily view and understand their bill and energy usage. Positioning this release prior to final deployment not only delivers benefits to customers sooner, but also allows the Company to more efficiently respond to increased call volume that will likely result as customers become more familiar with the new bill format.

In 2021, the Company will begin deploying the final components of the meter-to-cash solution ("Releases 5-8" or "Core Releases"). In addition to all meter-to-cash processes, the Company will begin providing customers with additional self-service capabilities and portals, new rate offerings and advanced billing options.

**Q. PLEASE DESCRIBE HOW THE COMPANY IS INCORPORATING CUSTOMER NEEDS AND EXPECTATIONS AS IT RELATES TO THE DESIGN AND IMPLEMENTATION OF CUSTOMER CONNECT.**

A. Based on the collective experiences with its current CIS, the Company knew its customer platform would need to meet the following core needs: (1) configurability; (2) adaptability; (3) and a customer-centric platform, not simply a meter-to-cash replacement. As a result of the extensive procurement process we conducted, the Company is confident that the SAP platform it selected meets these core needs. For example, this platform has been implemented by more than 760 utilities globally, including utilities that have already implemented things such as renewable generation and advanced metering infrastructure (AMI), and are utilizing its full capabilities. By selecting the SAP platform, the Company and its customers will get the benefit of the technology as well as the ability to leverage best practices from these other utilities to keep pace with the needs and expectations of our customers. Further, because this platform is being used globally by utilities and retailers, the SAP platform is constantly evolving and being updated to accommodate the latest technologies and user interfaces to help ensure that customers continue to derive benefits from the system.

As I stated in my direct testimony, the Company is currently in the Analysis and Design phase of the Customer Connect platform (*i.e.*, assessing how the Company will use the platform and how best to incorporate it into our business processes). As such, we have leveraged both industry research and internal survey methods to understand customer expectations. Industry research confirms that customer expectations are changing; they are more fluid and consumers benchmark us against other customer service companies such as Amazon and FedEx, where there is transparency and awareness in their processes. For example, we have all come to expect the capability to track our packages and see, at any given moment, where the package is and when it is projected to be at our home. We understand our customers have come to expect the same thing from all service providers, including their utility, and we are confident that the SAP platform gives us the technology we need to meet this expectation. To that end, during the Design phase, using the collective experiences with its current CIS, the Company will take an opportunity to redesign outdated business processes that have been in place for more than 20 years. For example, the Company's current CIS requires Customer Care specialists to obtain information such as directions to a customer's home and the location of the meter when completing a request to start or stop service. With the deployment of AMI meters, as well as common technologies, like GPS, obtaining this information is no longer necessary. Although this information is no longer needed for service orders, our system and internal processes have not evolved to allow for these efficiencies. This is our opportunity to shape the future.

Finally, the Company intends to perform customer outreach. For example, the Company is currently planning to survey customers to understand the value they are receiving from the new platform. Additionally, the Company intends to gather customer feedback via outreach methods such as crowdsourcing, surveys, interviews, focus groups and/or open forums to gather feedback during the design of the Company's new bill format.

**Q. WILL THE COMPANY AGREE TO PROVIDE SEMI-ANNUAL REPORTS REGARDING CUSTOMER CONNECT DEPLOYMENT AS RECOMMENDED BY PUBLIC STAFF WITNESS JACK FLOYD?**

A. While the Company is certainly amenable to providing any level of reporting required by the Commission, the Company questions whether the level of detail and frequency of reporting recommended by Public Staff is sufficiently valuable, especially if the Company is not allowed to recover its forecasted expenses as Public Staff witness Boswell recommends. Instead, the Company proposes to provide updates about the program annually.

## III. GREEN BUTTON CONNECT / ACCESS TO CUSTOMER DATA BY THIRD PARTIES

**Q. PLEASE BRIEFLY DESCRIBE NCSEA WITNESS MICHAEL MURRAY'S RECOMMENDATION REGARDING GREEN BUTTON CONNECT.**

A. Witness Murray recommends that the Company: (1) utilize "Green Button," including "Connect My Data," to provide usage data information to third parties; (2) provide historic use and current rate data to customers and third parties in machine readable (xml) format; and (3) establish a "user friendly" customer authorization process for recommendations 1 and 2 above.

**Q. HOW DO YOU RESPOND?**

A. First and foremost, it is important to understand the new Customer Connect platform will be capable of enabling new capabilities such as these, should they arise. Therefore, whether Customer Connect, as designed, can accommodate these capabilities is not an issue that needs to be addressed in this case. The Company believes that providing these capabilities will require both approval from this Commission and customer consent.

As it relates to the sharing of information with third parties, whether it is in the "Green Button" format or any other, the Company agrees with and defers to Public Staff witness Floyd's recommendation on page 35, lines 2-5 of his testimony, to protect customer data and adhere to the Code of Conduct as it relates to the sharing of customer information.[5] The Code of Conduct defines customer information as: "non-public information or data specific to a Customer or group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit

[5] The Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, activities, and transactions between and among the public and nonpublic utility operations (as they relate to the public utility operations) of Duke Energy and its affiliates in North Carolina, including DEC, DEP and Piedmont (the "Companies"). The Companies are bound by the Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682.

history that is or has been obtained or complied by DEC, DEP, or Piedmont in connect with supplying of Electric Services or Natural Gas Services to that Customer or group of Customers." Providing third parties with access to consumption and load profile data, which witness Murray recommends, would be in clear violation of the prohibition from disclosing customer information to third parties.

Further, in recommending the Company provide historic billing and rate information to customers and third parties in a machine-readable, automated manner, witness Murray does not mention that customers already have access to historic usage via the Company's external website. In fact, customers may view and download up to 24 months of historic usage data from the Company's website at any time in CSV file format. While the Company plans to assess the possibility of providing usage information to *customers* using programs such as "Green Button: Download My Data" in XML format, the timing and cost for such capability has not yet been determined. Additionally, the Company's rate schedules are publicly available via the Company's external website, where both customer usage data and our rate schedules may be accessed with ease.

## IV. CONCLUSION

**Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

BY MR. ROBINSON:

Q. Ms. Hunsicker, do you have a summary of your prefiled direct and rebuttal testimony?

A. I do.

MR. ROBINSON: Mr. Chairman, at this time, we would ask to move the summary into the record.

CHAIRMAN FINLEY: Without objection, it will be copied into the record as though given orally.

MR. ROBINSON: Thank you, Mr. Chairman.

(Whereupon, the summary of the prefiled direct testimony and prefiled rebuttal testimony of Retha Hunsicker was copied into the record as if given orally from the stand.)

**Duke Energy Carolinas, LLC**
**Retha Hunsicker Direct and Rebuttal Testimony Summary**
**Docket No. E-7, Sub 1146**

My direct testimony discusses the Customer Information System used by Duke Energy Carolinas LLC and explains why it is necessary to convert that system into a modern customer service platform, known as Customer Connect. Particularly, the current system is over twenty years old and is past the point where modular "bolt on" systems or upgrades are effective. Our business and our customers' needs are very different than they were when the original system was constructed. Customer Connect is the next generation customer platform with new customer engagement and integrated operations and analytics capabilities that will provide the customer with more choice, convenience and control over how they do business with us. The Customer Connect Program began analysis and design in January 2018 and is currently planned to be fully implemented for DE Carolinas in 2022. Each year, beginning in late 2018, the program will advance the final solution while providing value and new capabilities to customers throughout the deployment.

The Company is seeking to adjust its test year O&M expense associated with the project from approximately $4.4 million to approximately $15.1 million, which reflects the average expected annual O&M expenses for the project from 2018 through 2020. The Company derived these forecasted expenses by using the best and final offers of the selected vendors as the foundation for the estimates.

My rebuttal testimony responds to: (1) Public Staff witness Boswell's recommendation to remove the Company's requested forecasted operating expenses for the Customer Connect program; and (2) NCSEA witness Murray and EDF witness Alvarez's recommendation to utilize "Green Button" to provide usage information to third parties, and witness Murray's recommendations to provide historic usage and current rate data to customers and third parties in a machine readable format, and to establish a "user-friendly" customer authorization process.

In response to witness Boswell, I explained that the Company's request for the forecasted O&M are reasonable and aligns with new functionality that will be in-service and providing benefits to customers every year of the project, beginning in 2018. I also explain that the O&M expenses I request are known and measurable because the best and final offers from the RFP process were used as the foundation for the forecasted expenses. Specific costs to cover activities beyond the scope of the contracts but within the scope of the program, such as the effort to modify more than 100 interfacing systems, were then added, leveraging established program estimating techniques and assumptions.

In response to witnesses Murray and Alvarez, I raise an area of concern the Company identified as it relates to providing customer information to third parties via the Green Button platform. Additionally, in response to witness Murray, I further explain that the Company's rate schedules and customer usage data is already available to customers on their monthly bills and via the customer portal on the Company's website.

This concludes the summary of my direct and rebuttal testimony.

MR. ROBINSON: The witness is available for cross examination.

CHAIRMAN FINLEY: Cross examination?

CROSS EXAMINATION BY MS. THOMPSON:

Q. Good afternoon, Ms. Hunsicker. Gudrun Thompson representing North Carolina Justice Center, North Carolina Housing Coalition, SACE and NRDC.

CHAIRMAN FINLEY: Ms. Thompson, we are going to break about 4:00, so get in about 10 minutes worth, if you can, then we'll come back.

MS. THOMPSON: Okay. I think we can do this in 10 minutes. Thank you, Mr. Chairman. I am going to go ahead -- in the interest of moving things along, I'm going to go ahead and ask my co-counsel to pass out a packet of cross examination exhibits.

BY MS. THOMPSON:

Q. Ms. Hunsicker, one of the functions of the Company's proposed customer information system is customers' billing, correct?

A. That's correct.

Q. You would agree that it's important for customers to understand their bills?

A. Yes.

Q. And the Company wants to provide accurate information to customers about their bills, correct?

A. Yes.

MS. THOMPSON: Has the exhibit been handed out to --

CHAIRMAN FINLEY: Yes.

MS. THOMPSON: Have you received a copy of the exhibit?

MR. ROBINSON: Yes.

MS. THOMPSON: Okay. Mr. Chairman, I would like to mark this first exhibit in the stack as NCJC et al. Hunsicker Cross Examination Exhibit 1.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, NCJC et al. Hunsicker Cross Examination Exhibit No. 1 was marked for identification.)

BY MS. THOMPSON:

Q. Ms. Hunsicker, would you take a look at this exhibit that's been marked as Cross Examination Exhibit 1; do you recognize this?

A. The components of your electric bill?

Q. Yes.

A. Yes, ma'am.

Q. And would you agree with me that this is a fact sheet for Duke Energy Carolinas' customers, which I will represent to you that I downloaded this from the Company's website, but does this look familiar to you?

A. Yes, it does.

Q. And would you turn to the first page of that fact sheet, please? Do you see, under electric service, and then item A1, do you see that -- where it says basic customer charge?

A. I do.

Q. Is that the same thing as the basic facilities charge that's at issue in this case?

A. I believe so.

Q. And the current basic facilities charge is $11.80?

A. I believe that's correct.

Q. Okay. And let's turn to the second page.

Again, do you see item A1 under A, electricity service, and then item A1, basic customer charge?

A. I do.

Q. And that's -- again, that's the basic facilities charge at issue in this case, right?

A. I believe so.

Q. Can you read that description of the basic customer charge, please?

A. "The basic customer charge is a fixed monthly amount to cover the cost of maintaining your electric meter to your home or business, as well as maintaining customer records, billing, and other transactions affecting the account. It is applicable whether or not electricity is used."

Q. So this fact sheet says that the basic customer charge includes the cost of maintaining your electric meter, as well as maintaining customer records, billing, and other transactions, correct?

A. Yes. That's what it says.

Q. And it doesn't mention any other category of costs that go into the basic facilities charge, does it?

A. I do not see that on here.

Q. Okay. Let's turn to the next exhibit.

MR. THOMPSON: Mr. Chairman, I would like to have this marked as NCJC et al. Hunsicker Cross Examination Exhibit 2, please.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, NCJC et al. Hunsicker Cross Examination Exhibit No. 2 was marked for identification.)

BY MS. THOMPSON:

Q. Ms. Hunsicker, do you recognize this document?

A. Yes, I do.

Q. And can you explain to me what this is?

A. This is a bill.

Q. Would you agree with me that this appears to be a sample bill for a DEC customer named John Doe?

A. Absolutely.

Q. And I will represent to you that I downloaded this from the Duke Energy Carolinas website.

Does this appear to -- does this look familiar to you?

A. Yes.

Q. Okay. Does this exhibit accurately represent an actual bill for a DEC residential customer?

A. It looks like that, yes.

Q. Okay. Now, under -- do you see there under rate schedule description, it's on the right, sort of under the little box that says 119.80, there is a rate schedule description header?

A. Yes.

Q. And do you see under that there is some line items?

A. I do.

Q. So residential service; you see that?

A. Uh-huh. Yes.

Q. And home wiring repair plan, renewable energy rider, sales tax; do you see those line items?

A. I do, yes.

Q. And there is no line item on the sample bill or on a real bill for the basic facilities charge, is there?

MR. ROBINSON: Mr. Chairman, the Company objects. Ms. Hunsicker did not testify to any of this, nor would this be within the scope of her knowledge.

MS. THOMPSON: May I respond?

CHAIRMAN FINLEY: Overruled. Let me tell you something. Hold on. I don't want to hear this objection about it's beyond the scope of the testimony anymore. Let's get this clear. In North Carolina, that's not a valid objection under the rules of evidence in this state, so please proceed.

MS. THOMPSON: Thank you, Mr. Chairman.

BY MS. THOMPSON:

Q. Returning to the sample bill -- and customer billing is part of your area of expertise and part of your duties with the Company, correct?

A. It is part of what we will calc out of the new system, yes.

Q. And that is the subject matter that you are here to testify about today, correct?

A. The system is, correct, yes.

Q. Now, going back to the fact that this basic facilities charge is not broken out as a line item, is that due to any kind of limitation in the Company's existing customer information system?

A. I do not know that level of detail.

Q. Okay. So would you know -- is it within your knowledge whether, once the Company's $290 million CIS is fully deployed, whether including the basic facilities charge as a line item on the bill, would that be something that would be within the capability of that new system?

A. We will have a new bill design as a part of the delivery of the new system.

Q. Okay. I'm gonna come back to that new bill format in just a moment, but let's go ahead and turn to the next exhibit, please.

MS. THOMPSON: And Mr. Chairman, I would like to have this marked for identification as NCJC et al. Hunsicker Cross Examination Exhibit 3.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, NCJC et al. Hunsicker Cross Examination Exhibit No. 3 was marked for identification.)

BY MS. THOMPSON:

Q. Ms. Hunsicker, in your role as vice president of customer connect, customer operations for Duke Energy Business Services, do you support Duke Energy Florida?

A. That will be a part of our system as well. Just to be clear, I don't support any of the systems today. I am looking at and accountable for the solution that we're building out in the future.

Q. Okay. Thank you. That's helpful. I will ask you about this exhibit, and you can tell me -- if you don't know the answers, then that is fine, you can just say so.

So this I will represent to you -- well, let me just ask, do you recognize this exhibit?

A. I do.

Q. Okay. And what does it appear to be to you?

A. It is -- I think it's what we would find as we look to calculate the bill.

Q. I'm sorry, I couldn't hear that.

A. I think this is what we would find online to calculate the bill.

Q. Okay. So this is -- similar to the sample bill that's on the Duke Energy Carolinas website, this is kind of a fact sheet for customers -- for Duke Energy Florida customers; does that sound about right?

A. That sounds about right.

Q. Let's see. And let's turn to the second page of that exhibit, and you see this is "breakdown of the new 2018 monthly bill statement"?

A. I see that.

Q. And is this a breakdown of the new bill statement that is -- has come out after the most recent Duke Energy Florida rate case?

A. I don't know the answer to that.

Q. But it's -- it says what it says.

A. Uh-huh.

Q. So this -- to your knowledge, does this fact sheet or sample bill accurately represent the bill of a Duke Energy Florida's residential customer?

A. I would hope so.

Q. And you will see -- if you would look with me in that box that's headed residential load management, there is several line items on that -- in that box; do you see that?

A. I do.

Q. And one of them is customer charge; would you agree with me?

A. I see that.

Q. It says $8.82?

A. Uh-huh.

Q. There is a line item for that, and then there is a line item for the energy charge, fuel charge, and so on?

A. Yes.

Q. Okay. Thank you. Now, let's go back to that new bill format that you mentioned.

A. Okay.

Q. You mentioned this universal bill format that will be rolled out with the new CIS, correct?

A. Correct, uh-huh.

Q. And that is to help customers more easily view and understand their bill and energy usage?

A. That's correct.

Q. Okay. Will that new bill format break out

the basic facilities charge as a line item?
A. We have not done the design of the new bill format.
Q. Are you aware that, in the Company's 2009 rate case, E-7, Sub 909, the Commission's order granting a general rate increase and approving the amended stipulation in that case, the Attorney General proposed that the Commission direct Duke Energy Carolinas to provide the basic facilities charge as a line item?
A. I was not a part of that.
Q. Okay. Would you accept that, subject to check?
A. I would.
Q. And would you also accept, subject to check, that the Commission stated that, although it would not order this BFC to be broken out as a line item on bills at that time, that the Commission said it was interested in consumers having this and possibly other useful information on their bills and shall consider adding this information in a future docket; would you accept that?
A. I would accept that, pending check.
Q. And is this -- is including the BFC as a line

item on residential customer bills something that the Company is willing to consider as it rolls out the new bill format?

A. I think that's something we could consider.

Q. Okay. Just a couple more questions. Moving to a slightly different topic.

In response to intervenor testimony about sharing of customer data with third parties, you pointed to a code of conduct that governs sharing of customer data, among other things?

A. Correct.

Q. Now, DEC is bound by this code of conduct pursuant to a regulatory condition approved by the Commission in connection with the merger of Duke Energy and Piedmont Natural Gas, correct?

A. I'm not sure when it was created. I just know what the code of conduct is today.

Q. So you don't know anything about how that code of conduct came to be?

A. I do not.

Q. Okay.

MS. THOMPSON: Well, then I will end there. Thank you, Ms. Hunsicker.

THE WITNESS: Thank you.

CHAIRMAN FINLEY: We will take our afternoon break and come back at 4:15.

(At this time, a recess was taken from 4:00 p.m. to 4:15 p.m.)

CHAIRMAN FINLEY: Who is next?

CROSS EXAMINATION BY MR. LEDFORD:

Q. Good afternoon, Ms. Hunsicker. I'm Peter Ledford with the North Carolina Sustainable Energy Association. I believe most of my questions are gonna focus on your rebuttal testimony.

A. Okay.

Q. In your rebuttal testimony, you respond to the recommendations of NCSEA witness Michael Murray.

Do you have a copy of Mr. Murray's testimony with you?

A. I do.

Q. Could you flip to page 4 of his testimony?

A. I'm there.

Q. Thank you. Would you agree that, on lines 14 to 16 of his testimony, starting at little I, it reads that he recommends energy usage information transmitted through the Company's AMI network and back to the Company's CIS to be provided -- excuse me, provided to the consumer and authorized third parties?

A. I see that, yes.

Q. Okay. Thank you. On page 15 of your rebuttal testimony, you state that providing third parties with access to consumption load profile data, which Witness Murray recommends, would be in clear violation of the prohibition from disclosing customer information to third parties.

MR. LEDFORD: Mr. Chairman, at this time I would like to introduce an exhibit that's going to be passed around right now, and I am going to go ahead and pass two out at this time. (Pause.)

And Mr. Chairman, I would like to ask that the exhibit that states Code of Conduct at the top be marked as NCSEA Hunsicker Cross Exhibit 1.

CHAIRMAN FINLEY: So marked.

MR. LEDFORD: Thank you.

(Whereupon, NCSEA Hunsicker Cross Exhibit No. 1 was marked for identification.)

BY MR. LEDFORD:

Q. Ms. Hunsicker, have you had a chance to examine the document?

A. Briefly, yes.

Q. Thank you. Would you agree that this is a copy of the Company's code of conduct, as approved by the Commission, on September 29, 2016, when the Commission approved Duke Energy's merger with Piedmont Natural Gas?

A. Yes.

Q. Can you please point me to the provision in the code of conduct that would be violated by Mr. Murray's recommendation?

A. Down at the bottom of page 1, where it says "customers' information," that is what we are referring to.

Q. Okay. That's a definition; is it not?

A. Uh-huh.

Q. So Mr. Murray's recommendation would violate that definition?

A. I think we would have to understand. We would have to get clarity.

Q. Well, can I point you to a different provision in this?

A. Certainly.

Q. And it is on what is marked at the bottom as page 48.

A. Yes.

MR. LEDFORD: I apologize,

Commissioner Clodfelter, I didn't print the entire order, but I did print the entire code of conduct.

COMMISSIONER CLODFELTER: I actually already have this one.

BY MR. LEDFORD:

Q. Ms. Hunsicker, would you read section -- well, this is all Roman numeral 3(a), but could you read 2(b) on this page for me?

A. 2(b)?

Q. Yes.

A. "Except as provided in Section 3(a)(2), customer information shall not be disclosed to any affiliate or not-affiliated third party without customer consent, and then only to the extent specified by the customer."

Q. That's perfect.

A. Okay.

Q. Thank you. So without asking you to read the entirety of the code of conduct, there is an exception for Section 3(a)(2)(f).

Subject to check, would you agree that that has to do with things like releasing data pursuant to a court order or something like that?

A. Yes, I would.

Q. So could you please explain to me how NCSEA Witness Murray's recommendation that customers be able to authorize a third party to receive their energy usage data violates the Company's code of conduct?

A. Yeah. Let me talk a little bit about -- we all know that the SGTB order came out, right? And we also understand that we are going to have a forum to be able to talk about some of this. And so what I would like to do is talk about the fact that we really have no issue with providing capabilities, and the platform in which we are going to be building will be provide for those capabilities. But we are going to ask that, through this forum, we get some obligations met or get some alignment and understanding. And I want to talk about those four.

One of those things is the code of conduct, and make sure we understand what is required from regulators and that we have an understanding there. The other is to understand the customer consent. What does the consent look like? What do customers -- what are they giving consent for? So that will be one part of that. Another part of that really is trying to understand that whatever we do has no impact on the system or any kind of system security from a data-security perspective. We also want to understand ongoing monitoring of the platform. Is there going to be anything that would add additional cost to the business back to operations or to back office? And then we also want to understand the cost of such third-party access. So those are the things we hope to do in that forum.

Q. Okay. Thank you for that foreshadowing of what we have to look forward to after this case wraps up, but could you please explain to me how NCSEA Witness Murray's recommendation violates the Company's code of conduct, as you assert in your testimony -- rebuttal testimony?

A. It is -- we are just wanting to make sure that we are within the code of conduct. So the code of conduct, we don't want to share customers' information without their consent, and that is what we want to validate.

Q. I think that's perfectly fair, but you do characterize Witness Murray's testimony as violating the code of conduct. What I'm hearing you say today is that there needs to be clarity around the code of conduct?

A. We need to have clarity about what it is we want to do with the data, as well as clarity in the interpretation of the code of conduct. We also want to have a conversation to understand a lot of pieces allowing third-party access.

Q. So is it still your testimony that Mr. Murray's recommendation violates the code of conduct?

MR. ROBINSON: Objection. Asked and answered.

MR. LEDFORD: I don't believe she has.

CHAIRMAN FINLEY: No, it hasn't been answered. Answer the question, if you may.

THE WITNESS: Yeah. Personally, I believe that there is more to understand. I do think there is something there that could violate the code of conduct.

CHAIRMAN FINLEY: He wants to know if what he's recommending violates the code of conduct.

THE WITNESS: My belief is that it does.

BY MR. LEDFORD:

Q. So thank you. Your belief is that authorized access violates the code of conduct?

A. Yes.

Q. Thank you.

MR. LEDFORD: All right. Mr. Chairman, I additionally passed out a second document at the same time. I would ask that that be premarked as NCSEA Hunsicker Cross Exhibit 2.

CHAIRMAN FINLEY: Shall be so marked.

MR. LEDFORD: Thank you.

(Whereupon, NCSEA Hunsicker Cross Exhibit No. 2 was marked for identification.)

BY MR. LEDFORD:

Q. Ms. Hunsicker, are you aware of whether Green Button connect, which was recommended by Witness Murray, requires of customer to consent to sharing of that data?

A. I believe it does.

Q. Okay. Could you please read the very first paragraph of the NCSEA Hunsicker Cross Examination Exhibit 2 under "utility customer engagement"?

A. "Green Button energy and water data access standard enables grid, electric, and water utilities to offer customers access to their usage data and empower them to securely share those data with authorized third-party service providers that can help them further monitor and manage their energy or water consumption."

Q. So you would agree that says customers may authorize third parties to receive access?

A. It does.

Q. All right. And it's still your assertion that it violates the Company's code of conduct?

A. Yes.

Q. Okay. Switching gears, I would like to ask a couple of questions about the development of the customer information system.

A. Absolutely.

Q. In your Progress -- in your testimony in the DEP case a couple of months ago, you stated that the Company had considered but dismissed Green Button. At that time, at least for me, it wasn't clear if you were referring to Duke Energy Progress or Duke Energy Corporation.

Are you aware of whether Duke Energy Carolinas or Duke Energy Corporation has considered Green Button?

A. I think we have, and we are looking forward to the forum in which we are going to be able to talk about third-party access at a deeper level.

Q. Has the Company estimated the cost to implement Green Button?

A. Not that I'm aware of.

Q. Okay. Do you believe it would be more expensive to integrate data access, such as Green Button, at the time the CIS is being developed, that is on the front end before it's deployed, or to add it afterwards in the form of a bolt-on?

A. We really haven't looked at that, so that's hard for me to say.

Q. Okay.

A. Uh-huh.

Q. And are you aware of the difference between Green Button download and Green Button connect?

A. I am.

Q. Okay. Moving away from customer access to energy consumption data.

Is there a relationship between the Company's outage management system or outage management software and the customer information system?

A. It would just be an interface.

Q. Is a portion -- is a goal of the new CIS that's being deployed to link the two of them?

A. It would be linked in the same way it's linked today. It's not a new linkage.

Q. Okay. There is no additional integration?

A. Correct.

Q. Is it accurate to say that J.D. Power reports, which are used widely by Duke Energy in measuring its customer satisfaction, report that satisfaction is much higher when customers receive information about outages?

A. Yes.

Q. Okay. So has the Company investigated linking in greater detail its outage management system with its new CIS?

A. We have not. We are right now in -- just starting design, right? And so, as we walk through design, we will be looking at the interfaces. But the ability to be able to reach out to customers about their outages really rests in two places. The first place is that you have to have your outage systems up to speed and be able to be communicating back with some level of communication. And outbound communication, or whatever that interface is, we have those today.

As we think about customer connect, one of the great things that we are going to be able to do is begin to understand our customers at a much more granular level. We are going to understand our customers' preferences. We are going to begin to be able to tailor and personalize information to them. So the interface is the same, but the data -- the understanding in which we know you, as a customer, will be greater because of the customer platform.

Q. Is it fair to say that you agree with me that it would be beneficial to ratepayers, or at least to the customer satisfaction of ratepayers, if the two were linked in some greater manner?

A. I think customers want to know -- I don't know if they need to be linked greater, but I think we need to know our customers, we need to have a platform that works off of customers not meters, which is what we have today. So the fundamental data model of our CIS needs to change. Once we are able to change that and house personalization, then we will be able to communicate to that customer in the way they wish to hear about their outage. Today, the interface, we have a couple of ways to be able to communicate with that customer. Those things will be a lot better in the future and a lot more personalized. The interfaces I don't think really have anything to do with it. It's about the capabilities that you enable, which is what we are doing.

Q. Fair enough. And forgive me if I forget the exact word you used in you testimony, but you talk about the CIS being rolled out in various, I believe it's releases over the coming years.

Is that something you anticipate the Company investigating, as to whether that would be available in the future, release of the CIS?

A. It will be available. And yes, we are rolling out, because we want customers to receive benefits of customer connect every year and along the way. So we will have two deployments in '18, one in '19, one in '20, and then 2 in '21 and '22.

Q. At this time, do you know when the information sharing between the outage management software and the CIS will begin, or is that, sort of, to be determined?

A. That is to be determined. There will be communications that probably will roll out early, which gives us more granularity in knowing the customer, and then the actual interface into the new CIS will not be until the new CIS deploys.

MR. LEDFORD: Great. Thank you. No further questions.

CHAIRMAN FINLEY: Mr. Finnigan, do you have questions?

MR. FINNIGAN: No, Your Honor.

CHAIRMAN FINLEY: Who is next?

CROSS EXAMINATION BY MS. ROSENTHAL:

Q. Sherri Zann Rosenthal, City of Durham. You may know -- do you know that the City of Durham's sustainability officer has asked Duke Energy for various information about citizen and geographic use of energy within Durham?

A. I'm not aware of that.

Q. And the sustainability officers for Durham, and Chapel Hill, and some of the other cities have gotten together to talk about the usefulness of shared data that they have.

When you are holding these forums, have you thought about having representatives from the cities there, in particular the sustainability officers?

A. The forum has not been set up yet, so that forum is going to be in place, I think, June 2nd or something like that. We have to have a plan in place for that.

Q. Could you add -- the purpose of my questions is to bring to the Company's attention that the sustainability officers have been very interested in the customer usage, energy usage data, depersonalized, because we have launched various waves of weatherization programs, and in targeting where we should put our money to help weatherize housing units, this information is very helpful. So if you could take that into account as you're designing your program to get some feedback, that would be very appreciated.

A. Okay. I just want to make sure that we're clear --

CHAIRMAN FINLEY: Pull that mic around, Ms. Hunsicker.

THE WITNESS: I want to make sure that we are clear on a couple of things. One of those is that we are really going to being looking at usage off the AMI meters, right? So that will be, kind of, what the forum is about. I'm not in a position to be able to say "yes" or "no" to that, but we could certainly take that back and make sure that we consider that.

MS. ROSENTHAL: Thank you.

CHAIRMAN FINLEY: Ms. Harrod?

MS. HARROD: Thank you, Mr. Chairman.

CROSS EXAMINATION BY MS. HARROD:

Q. Ms. Hunsicker, Jennifer Harrod with the AG's Office. And I understand you're employed by DEBS, so if I say "the Company," I guess we all use that term kind of loosely, but I think for the purposes of my questions, I think they are governed by the code -- around the code of conduct, so I think I am talking about both DEC and DEP. But if you need to make more clarification around who we are talking about, please do.

A. Okay.

Q. This question is specific to AMI data, but it could really apply to any data.

Who owns the data that is collected by a customer's -- a single customer's meter; who owns that data?

A. That's kind of a hard thing to say. I would say that's joint ownership.

Q. Okay.

A. That would be customer data, as well as it would be Company, based on the algorithms that we apply and the technology that goes against it.

Q. Okay. And then same question with respect to customer data and the aggregate, all of the information collected from the meters or any subset of information collected from the meters; who owns that data?

A. I think it would be the same.

Q. Okay. Has the Company had any conversations about or made any plans concerning selling that data, or monetizing it, or profiting from it in any way?

A. I'm not aware of anything like that.

Q. Okay. I just -- I noticed, in the code of conduct, there is a section on marketing that implies that at least the customer list has been -- you know, could be made available for marketing purposes.

Would you agree with me that, given the fact that the meters are ultimately paid for by ratepayers, that any financial -- and I'm not endorsing the Company selling customer information, just for the record, so by asking this question, I don't mean to be endorsing that as a good plan, but were the Company to do so, would you agree with me that, a minimum, that the profits from that enterprise ought to roll back to the customers who ultimately paid for that equipment?

A. Yeah. I'm not in that area, so it's really hard for me to answer that.

Q. Okay. Fair point. Is that the type of thing -- so in other words, I don't have a lot of information about this forum you are talking about in

June.

Is that the type of thing -- I know the -- probably the security of customer information is on the table, but is the use of that information for purposes other than the provision of electric service something that would be appropriate to consider in that forum?

A. I'm not sure that that's part of what's in the forum today. That's something that we could certainly take back. I think really it is a third party -- my understanding of reading the order is that it is about third-party access, and what we would make available, how we would make it available. And back to what I suggested earlier is we really want to understand a few tenets, to make sure that we are being very diligent with the data that we store for our customers.

MS. HARROD: Okay. Thank you. I don't have any further questions.

CHAIRMAN FINLEY: Public Staff?

UNIDENTIFIED FEMALE: No questions.

CHAIRMAN FINLEY: Redirect?

MR. ROBINSON: Just a couple, Mr. Chairman.

REDIRECT EXAMINATION BY MR. ROBINSON:

Q. Ms. Hunsicker, do you recall NCJC witness -- excuse me, attorney Thompson comparing definitions of the basic customer charge between North Carolina and Florida?

A. I do.

Q. Can I turn to your attention to NCJC Cross Exam Exhibit 3, page 2? Do you see the definition of customer charge there?

A. Yes, I do.

Q. Okay.

A. Is that the one I read earlier?

Q. Yes. Do you recall reading that?

A. Yes.

Q. Do you mind just reading it again for the record?

A. Certainly.

Q. Oh, you did not read it. So NCJC Cross Exhibit 3, page 2.

A. The Florida one?

Q. Yes.

A. Mine aren't marked. I'm sorry.

Q. Can you please read it?

A. I can. "Customer charge. A fixed monthly amount to cover the cost of providing service to your location. This charge is applicable whether or not electricity is used."

Q. Okay. And is there any difference, from your knowledge, between the components of the charge in Florida based off of that definition versus the definition in North Carolina?

A. I don't see any difference.

Q. Okay. And, Ms. Hunsicker, is there a witness in the Company's case that can better discuss the customer charge and the various components?

A. Absolutely. That would be Witness Pirro.

MR. ROBINSON: Okay. Nothing further.

CHAIRMAN FINLEY: Questions by the Commission? All right. Thank you, Ms. Hunsicker. You may be excused, and we will receive her exhibits in evidence and the NCSEA and NCJC Cross Examination exhibits into evidence.

(Whereupon, Hunsicker Exhibit No. 1 NCSEA Hunsicker Cross Exhibit Nos. 1 and 2 and NCJC et al. Hunsicker Cross Exam Exhibit Nos. 1 through 3 were marked for identification.)

MR. SOMERS: Mr. Chairman, the Company will call Mr. Donald Schneider.

CHAIRMAN FINLEY: Okay.

DONALD SCHNEIDER,

having first been duly sworn, was examined

and testified as follows:

DIRECT EXAMINATION BY MR. SOMERS:

Q. Good afternoon, Mr. Schneider. The long wait is over.

A. Good afternoon.

Q. Would you state your name for the record?

A. It's Donald Schneider, Junior.

Q. And what is your business address?

A. 400 South Tryon, Charlotte, North Carolina.

Q. And what do you do for a living?

A. My title is manager -- excuse me, general manager of AMI program management.

Q. And is that for all of Duke Energy or certain segments within the Company?

A. For all of Duke Energy.

Q. Have you caused to be prefiled in this matter direct testimony on or about August 25, 2017, of 10 pages?

A. I did.

Q. And do you have any corrections or revisions to your prefiled direct testimony?

A. I do not.

Q. So if I were to ask you the same questions here today, would your answers be the same?

A. Yes, they would.

MR. SOMERS: Mr. Chairman, I move that Mr. Schneider's prefiled direct testimony be entered into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Schneider's direct prefiled testimony of August 25, 2017, consisting of 10 pages is copied into the record as though given orally from the stand.

MR. SOMERS: Thank you.

(Whereupon, the prefiled direct testimony of Donald Schneider was copied into the record as if given orally from the stand.)

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-7, SUB 1146**

| | | |
|---|---|---|
| In the Matter of: | ) | |
| | ) | **DIRECT TESTIMONY OF** |
| Application of Duke Energy Carolinas, LLC | ) | **DONALD SCHNEIDER, JR.** |
| For Adjustment of Rates and Charges | ) | **FOR DUKE ENERGY** |
| Applicable to Electric Service in North Carolina | ) | **CAROLINAS, LLC** |

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Business Services, LLC ("DEBS"), as General Manager, Advanced Metering Infrastructure ("AMI") Program Management. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

**Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS GENERAL MANAGER, AMI PROGRAM MANAGEMENT, FOR DUKE ENERGY.**

A. My duties and responsibilities include managing the project execution of all AMI or "smart meter" related projects for all Duke Energy jurisdictions and management of Duke Energy's AMI Operations organization which has responsibilities for day-to-day management and monitoring of the AMI network.

**Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.**

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville (Indiana) in 1986. Upon graduation, I was employed by Duke Energy Indiana (then known as Public Service Indiana) as an electrical engineer. Throughout my career with Duke Energy, I have held various positions of increasing responsibility in the areas of engineering and operations, including distribution planning, distribution design, field operations, and capital budgets. In 2006, I was named General Manager, Midwest Premise Services, responsible for managing all of Duke Energy's Midwest premise service and meter reading departments. Following this, in 2008, prior to the Duke Energy/Progress Energy merger, I was promoted to a position responsible for managing the project execution for all Grid Modernization projects in the field, including both AMI and Distribution Automation ("DA") devices, for all legacy Duke Energy jurisdictions. In 2012, following the Duke Energy/Progress Energy merger, I was named to my current position. Additionally, I have been registered as a professional engineer with the State Board of Registration for Professional Engineers in the state of Indiana since 1995.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION OR ANY OTHER REGULATORY BODIES?**

A. I have not testified before this Commission; however, have testified for Duke Energy Ohio before the Public Utilities Commission of Ohio, Duke Energy Kentucky before the Kentucky Public Service Commission and Duke Energy Indiana before the Indiana Utility Regulatory Commission in cases related to AMI and smart grid topics.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to discuss the Company's status in implementing AMI technology, including deployment timelines, in the DE Carolinas North Carolina service territory.

## I. SUMMARY OF TESTIMONY

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. Approximately 574,000 DE Carolinas North Carolina customers have received smart meters as of year's end 2016. Current projections show a total of over 1 million smart meters deployed for DE Carolinas North Carolina customers by the end of November 2017.

Smart meters allow customers access to more detailed usage information (down to the hour) via the customer portal. Meter reads, monthly and for the purpose of transferring service ("off-cycle"), can be performed remotely for all customers, eliminating the need for a technician to come to the customer's premise. Additionally, service connections and disconnections can be performed remotely for the majority of customers who are starting and/or stopping service, again, eliminating the need for a technician to come to the customer's premise. During storm outages, damage assessment and repair verification can be done much more quickly when customers have a smart meter.

## II. ADVANCED METERING INFRASTRUCTURE

**Q. ARE YOU FAMILIAR WITH THE EXISTING AUTOMATED METER READING SYSTEM OF DUKE ENERGY CAROLINAS?**

A. Yes. Beginning in 2002, DE Carolinas began exchanging analog meters with Automated Meter Reading meters so that meter reading equipment installed in vehicles could gather kWh usage via a 900 MHz radio frequency ("RF") signal. During the deployment DE Carolinas exchanged the analog meters with either a digital Automated Meter Reading meter or an analog meter retrofitted with an RF radio transmitter inside (collectively "AMR Meters"). AMR meters were deployed for the vast majority of customers and monthly meter reading was no longer performed by having to physically visit each meter, but instead was performed monthly as vehicles drove through neighborhoods collecting the readings being transmitted by the AMR meters.

**Q. ARE THERE ANY LIMITATIONS WITH DE CAROLINAS' CURRENT SYSTEM?**

A. Yes. While the current AMR system provided efficiencies over physically visiting and reading each meter, its single monthly meter readings provide limited energy usage information. The current system also requires vehicles to drive through neighborhoods for readings. Finally, the one-way communications with AMR meters does not supply customers or the Company with expanded capabilities for enhanced customer programs and services.

**Q. WHAT IS ADVANCED METERING INFRASTRUCTURE?**

A. AMI meters - often referred to as smart meters - are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability. The system utilizes an RF mesh architecture, which is flexible in that the meters within the mesh network establish an optimized RF communication path to a collection point either through other meters or, in some cases, through network range extenders.

The AMI implementation is not a simple meter change-out project. In addition to changing out the meters, AMI covers all of the components necessary to communicate with the advanced meters and collect usage data and event information from them. The system includes advanced meters, a two-way communication network, and central computer systems.

**Q. DESCRIBE THE CURRENT IMPLEMENTATION OF ADVANCED METERING INFRASTRUCTURE ACROSS THE DE CAROLINAS SYSTEM.**

A. Based on previous experience deploying smart meters in other Duke Energy jurisdictions, DE Carolinas is deploying the AMI technology by zones. To efficiently and effectively deploy AMI, the Company first strategically places the collection point equipment in a deployment zone. Then the Company installs the smart meters that will communicate through that collection point equipment or other nearby collection point equipment, allowing some overlap for redundancy purposes. This process is repeated on a rolling basis, in that the Company will begin new zones while deployment in other zones is underway. Once deployment is complete in a zone, there may still be ongoing work to relocate collection points or install range extenders in order to optimize the communication network.

As of December 31, 2016, DE Carolinas had installed approximately 574,000 smart meters in its North Carolina service territory. As of June 30, 2017, the Company had installed a total of 756,000 smart meters in its North Carolina service territory. DE Carolinas has continued installing additional meters, forecasting a total of approximately 1,091,000 across its North Carolina service territory by November 30, 2017. The plan is to continue AMI implementation through mid-2019 for all remaining DE Carolinas North Carolina customers' meters in scope.

**Q. HOW WILL THE ADVANCED METERING INFRASTRUCTURE IMPLEMENTATION DIRECTLY BENEFIT THE COMPANY'S CUSTOMERS?**

A. The AMI technology is customer-focused; it enables greater convenience, control and transparency over a customer's energy consumption. Customers with smart meters will have access to detailed information about their hourly and daily usage patterns through the Duke Energy customer portal so they can make more informed choices regarding how they use energy. With the capability to record interval usage data, smart meters are a foundational technology that can enable new rate designs, as referenced in Witness Pirro's testimony. This additional data, combined with the new Customer Information System, referenced in Witness Hunsicker's testimony, will provide the Company with expanded options and flexibility in supporting enhanced services and rate offerings.

Additionally, two new customer programs are now available to DE Carolinas customers with smart meters. Pick Your Due Date allows eligible customers to select their desired billing due date from the 1st to the 31st of the month, better aligning with a customer's needs. Usage Alerts provides eligible customers with an alert at the midpoint of their billing cycle showing their accumulated charges and forecast of their month-end bill. Usage Alert customers can customize their experience by choosing to receive threshold alerts that notifies them when their charges are approaching/exceeding their monthly budget. Usage Alert customers can further set and change their alert preferences in the usage alert management tool and set a budgeted dollar amount and change their alert channel to text message.

All customers receiving smart meters will benefit from the greater convenience that enables DE Carolinas to perform regular meter reads and off-cycle meter reads remotely. Additionally, customers will experience the convenience of not needing to schedule a technician to visit their premise when they request that their electric service be connected or disconnected. Likewise, electric customers who become eligible for disconnection for non-payment will have power restored more quickly through the remote reconnect capability, than they would if DE Carolinas had to send a technician on site.

Finally, smart meters will be integrated into Company efforts to increase communications with customers about outages and restoration timelines. DE Carolinas will have the capability to interrogate individual smart meters or masses of smart meters to determine if customers have power. During the damage assessment phase of a storm, the mass meter interrogation capability allows the Company to have a better view of where outages are located on the system. This functionality helps reduce the assessment time, thus reducing outage durations for customers. During the power restoration phase of a storm, the capability of mass meter interrogation enables the Company to determine whether power has been restored to each meter before leaving an area. For example, today, if the Company restores power to a circuit that was experiencing an outage, DE Carolinas does not know whether each individual home has been restored along that circuit. It could happen that power is restored to nearly all of the homes along the circuit, but that one or two homes continue to be without service due to some other individual issue. The Company presently has no way of knowing if this has occurred until the customer notifies DE Carolinas that they are still without service, and by that time, the Company's crew may have moved on to a new area. Smart meters will allow the Company to know whether individual customers are back in service before the Company moves on. And lastly, during the cleanup phase of a storm, when the Company is clearing out single-outage tickets, the capability of interrogating individual meters can tell the Company when customers power has already been restored, saving a truck roll to confirm power has been restored.

**Q. ARE COSTS FOR THE ADVANCED METERING INFRASTRUCTURE IMPLEMENTATION INCLUDED IN THIS RATE CASE?**

A. Yes, costs of the smart meter implementation are included in this rate case. In 2016 the Company spent $73.9 million across the system in North and South Carolina. Through pro forma adjustments, the Company has included North Carolina retail's share of actual and estimated costs of implementation for the period January through November 2017 of $123.1 million for the system. Pro forma and North Carolina specific adjustments in this rate case are discussed in the testimony of Witness McManeus. In addition, Witness McManeus requests permission to use a regulatory asset to address the cost recovery of meters that will be replaced by the smart meter implementation.

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.

BY MR. SOMERS:

Q. Mr. Schneider, did you also cause to be prefiled rebuttal testimony in this matter of some 17 pages on or about February 6, 2018?

A. Yes, I did.

Q. Do you have any changes or corrections to your prefiled rebuttal testimony?

A. I do not.

Q. So if I were to ask you the same questions here today on the stand, would your answers be the same?

A. Yes, they would.

MR. SOMERS: Mr. Chairman, I would move to admit into the record Mr. Schneider's rebuttal testimony, as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Schneider's rebuttal testimony of 17 pages of February 6, 2018, is copied into the record as though given orally from the stand.

MR. SOMERS: Thank you.

(Whereupon, the prefiled rebuttal testimony of Donald Schneider was copied into the record as if given orally from the stand.)

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

**DOCKET NO. E-7, SUB 1146**

| | | |
|---|---|---|
| In the Matter of: | ) | |
| | ) | **REBUTTAL TESTIMONY OF** |
| Application of Duke Energy Carolinas, LLC | ) | **DONALD SCHNEIDER, JR.** |
| For Adjustment of Rates and Charges | ) | **FOR DUKE ENERGY** |
| Applicable to Electric Service in North | ) | **CAROLINAS, LLC** |
| Carolina | ) | |

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed by Duke Energy Business Services, LLC ("DEBS"), as General Manager, Advanced Metering Infrastructure ("AMI") Program Management. DEBS provides various administrative and other services to Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

**Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?**

A. Yes. I caused to be pre-filed direct testimony on behalf of DE Carolinas.

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my testimony is to respond to portions of the direct testimony filed by Public Staff witnesses Jack L. Floyd, North Carolina Sustainable Energy Association ("NCSEA") witness Michael E. Murray, and Environmental Defense Fund ("EDF") witness Paul J. Alvarez regarding DE Carolinas implementation of AMI meters and various recommendations they have made to the Commission.

## I. <u>SUMMARY OF TESTIMONY</u>

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I will respond and clarify questions that Public Staff witness Floyd and EDF witness Alvarez had about the DE Carolinas AMI cost-benefit analysis and explain further how a foundational investment of AMI enables increased customer value. I join in agreement with Public Staff witness Floyd encouraging the Commission to rule on the AMI opt-out tariff filed by the Company in July 2016. Additionally, I will further support DE Carolinas' request that new AMI meters receive a 15-year depreciation life instead of the 17-year life recommendation from the Public Staff. I explain that the current proceeding combined with DE Carolinas' annual Smart Grid Technology Plan ("SGTP") filings offer the Commission, Public Staff and other interested parties the ability to investigate and comment on the Company's AMI plans without requiring a separate docket or proceeding. Finally, I respond to NCSEA's witness Murray's request that the Commission adopt a "bring your own device" requirement as part of this rate case.

## II. ADVANCED METERING INFRASTRUCTURE

**Q. IN HIS TESTIMONY AT PAGE 42, PUBLIC STAFF WITNESS FLOYD STATES THAT "I AM GENERALLY SUPPORTIVE OF THE ANALYSES PROVIDED BY THE COMPANY" AND ON PAGE 45 "THE COMPANY HAS MADE A REASONABLE ASSESSMENT OF THE COSTS AND BENEFITS ASSOCIATED WITH ITS PROPOSED DEPLOYMENT OF AMI," BUT AT PAGES 40-43, HE NOTES A FEW CONCERNS WITH THE AMI COST-BENEFIT ANALYSIS PERFORMED BY THE COMPANY. FIRST, HOW DO YOU RESPOND TO HIS CONCERNS ABOUT THE NON-TECHNICAL LOSS BENEFITS INCLUDED IN THE ANALYSIS?**

A. DE Carolinas provided a discussion of, and cost-benefit analysis for, its AMI project plan in the Company's SGTP filed on October 2, 2017 in Docket No. E-100, Sub 147, as well as in response to data requests in this rate case.

As pointed out by Witness Floyd, the Company is basing the reduction in non-technical line loss benefit on a 2008 EPRI report titled "Advanced Metering Infrastructure Technology - Limiting Non-Technical Distribution Losses In The Future" that was prepared by industry experts. According to the 2008 EPRI report, industry experts project that a reasonable percentage for non-technical losses is 2 percent of gross revenue. This assumption was utilized as a basis in calculating the DE Carolinas AMI non-technical loss reduction benefit. This benefit item represents expected revenue capture during and after an AMI project as a result of the increased ability to identify, correct and/or collect cases of non-performing or under-performing ("slow/stuck") meters from registration erosion, power theft and pilferage by way of either direct tapping, manipulating, or bypassing the meter, non-reading of meters, and misconfigured equipment and installation errors such as mis-wiring, incorrect application of multiplying factors, and defects in current transformer ("CT") & potential transformer ("PT") circuitry.

As reported in the December 15, 2017 filing in Docket Nos. E-7, Sub 1115 and E-100, Sub 147 analyzing Non-Technical Loss ("NTL") is significantly complex and it would not be possible to use the actual historical kilowatt-hour and lost revenue data for energy theft that DE Carolinas has experienced, as the Company is only able to measure what has been identified. Nevertheless, the Company provided an estimate of the costs and benefits for the AMI deployment using the Commission-requested adjustments to its AMI cost-benefit methodology. Analytics capabilities for revenue protection with AMI are continuing to develop as more AMI data becomes available. A full deployment of AMI is expected to further enhance revenue loss identification abilities and the Company is striving to maximize capture of NTL.

**Q. PUBLIC STAFF WITNESS FLOYD ALSO STATES ON PAGE 42 OF HIS TESTIMONY THAT THE PUBLIC STAFF IS CONCERNED THAT DE CAROLINAS "WILL NOT IMMEDIATELY MAXIMIZE THE BENEFITS AVAILABLE TO CUSTOMERS FROM AMI." HOW WILL AN AMI PROJECT DIRECTLY BENEFIT THE COMPANY'S CUSTOMERS, AND HOW WILL THE COMPANY "MAXIMIZE" THE BENEFITS?**

A. AMI is a foundational investment that will enable DE Carolinas to provide customers with greater convenience, choice, control and transparency over their energy consumption. Public Staff witness Floyd mentions that "without access to all of the functionalities of AMI, customers will not experience the greater convenience and control of usage that should be available to them." He then goes on to describe some specific ways that Duke Energy should address his concern about benefit maximization. As I describe below, the Company is already working to address those concerns.

On page 43 of his testimony, Public Staff witness Floyd says, "DEC should produce rate designs that include new TOU rate structures that provide stronger price signals to shift load." With the capability to record interval usage data, smart meters are a foundational technology that can enable new rate designs, as referenced in Company witness Pirro's rebuttal testimony. This additional data, combined with the new Customer Connect project, referenced in Company witness Hunsicker's rebuttal testimony, will provide DE

Carolinas with expanded options and flexibility in supporting enhanced services and rate offerings.

Public Staff witness Floyd also says on page 43 of his testimony that DE Carolinas' AMI deployment "should also result in new payment options including allowing customers to prepay for electricity. One new payment option that has already been implemented for DE Carolinas customers with AMI meters is Pick Your Due Date, which allows eligible customers to select their desired billing due date from the 1st to the 31st of the month, better aligning with a customer's needs. Additionally, it just so happens that the Company filed a Prepaid Advantage energy efficiency pilot program on January 16, 2018 in Docket No. E-7, Sub 1167. Participants in the pilot will pay in advance and settle daily for their energy use, rather than being billed for usage after it has occurred. The pilot is designed to facilitate customers' control over their energy use and enable bill management for residential customers by allowing customers to pay the amount they choose when they choose, thereby avoiding unexpectedly high bills and non-pay disconnects.

Finally, Public Staff witness Floyd says on page 43 of his testimony, "DEC should also produce informational tools and applications that provide more granular and timely data to allow customers greater insight and control over their actual usage." Customers with AMI meters have access to detailed information about their hourly and daily usage patterns through the Duke Energy customer portal so they can make more informed choices regarding how they use energy. Also, as part of continuing to build upon the foundational investment of AMI, an additional enhanced customer service was implemented for DE Carolinas customers referred to as Usage Alerts. The Usage Alerts offering provides AMI metered customers with an alert at the midpoint of their billing cycle showing their accumulated charges and forecast of their month-end bill. Usage Alert customers can customize their experience by choosing to receive threshold alerts that notifies them when their charges are approaching/exceeding their monthly budget. Usage Alert customers can further set and change their alert preferences in the usage alert management tool and set a budgeted dollar amount and change their alert channel to text message.

Public Staff Witness Floyd says, "The Public Staff's support for the AMI deployment is predicated on maximizing these non-quantifiable benefits for customers," but the Company notes that it will provide even more benefits for customers through its AMI deployment. All customers receiving AMI meters are benefiting from the greater convenience that enables DE Carolinas to perform regular meter reads and off-cycle meter reads remotely. Additionally, customers experience the convenience of not needing to schedule a technician to visit their premise when they request that their electric service be connected or disconnected. Likewise, electric customers who become eligible for disconnection for non-payment have power restored more quickly through the remote reconnect capability, than they would if DE Carolinas had to send a technician on site.

Finally, AMI meters are being integrated into Company efforts to streamline restoration efforts. DE Carolinas has the capability to interrogate individual AMI meters or masses of AMI meters to determine if customers have power. During the damage assessment phase of a storm, the mass meter interrogation capability allows the Company to have a better view of where outages are located on the system. This functionality helps reduce the assessment time, thus reducing outage durations for customers. During the power restoration phase of a storm, the capability of mass meter interrogation enables the Company to determine whether power has been restored to each meter before leaving an area. For example, today, if the Company restores power to a circuit that was experiencing an outage, DE Carolinas does not know whether each individual home has been restored along that circuit if they don't have an AMI meter. It could happen that power is restored to nearly all of the homes along the circuit, but that one or two homes continue to be without service due to some other individual issue. With the legacy meters the Company has no way of knowing if this has occurred until the customer notifies DE Carolinas that they are still without service, and by that time, the Company's crew may have moved on to a new area. AMI meters allow the Company to know whether individual customers are back in service before the Company moves on. And lastly, during the cleanup phase of a storm, when the Company is clearing out single-outage tickets, the capability of interrogating individual meters tells the Company when customers' power has already been restored, saving a truck roll to confirm power has been restored.

**Q. PUBLIC STAFF WITNESS FLOYD ALSO ENCOURAGES THE COMMISSION TO ISSUE AN ORDER ON THE OPT-OUT PROGRAM FILED BY DE CAROLINAS IN DOCKET NO. E-7, SUB 1115. HOW DO YOU RESPOND?**

A. DE Carolinas agrees that customers should have the choice to opt-out of the AMI meter through a cost-based tariff. The Company agrees with the Pubic Staff that the Commission should approve the opt-out program as filed, and respectfully requests approval by the Commission soon.

**Q. ON PAGE 46 OF HIS TESTIMONY, PUBLIC STAFF WITNESS FLOYD RECOMMENDS THAT THE COMPANY FILE AN UPDATED COST-BENEFIT ANALYSIS THAT IS BASED ON THE ACTUAL AMI DEPLOYMENT COSTS INCURRED IN ITS NEXT BASE RATE CASE. HOW DO YOU RESPOND?**

A. DE Carolinas does not believe that such an additional cost-benefit analysis should be required. The Company's decision to fully deploy AMI meters to its customers has been made and the Public Staff and Commission have the necessary information and tools to determine their positions on recovery of those costs based upon the information the Company had at the time the relevant decision was made. Such a requirement would be burdensome and costly and, although I am not an attorney, I believe it would be contrary to the North Carolina ratemaking principles which do not allow a "hindsight" analysis. Having said that, DE Carolinas' deployment of AMI is cost-effective and beneficial to its customers and the Company stands by its decision.

Q. **PUBLIC STAFF WITNESS FLOYD RECOMMENDS AT THE COMPANY'S NEXT BASE RATE CASE THAT IT FILE "A DETERMINATION OF THE ACTUAL NON-TECHNICAL LOSS BENEFITS THAT ARE REALIZED, INCLUDING SAMPLE CASE STUDIES THAT WOULD ILLUSTRATE THOSE BENEFITS AND HOW THOSE BENEFITS HAVE IMPACTED THE COMPANY'S BASE REVENUE ITEMS THAT COMPRISE THE NTLS." HOW DO YOU RESPOND?**

A. The Company is willing to work with the Public Staff about how to best provide information about this benefit in the next rate case.

Q. **ON PAGE 20 OF HER PRE-FILED DIRECT TESTIMONY, PUBLIC STAFF WITNESS MCCULLAR RECOMMENDS THAT DE CAROLINAS UTILIZE A 17-YEAR AVERAGE SERVICE LIFE FOR AMI METERS AS OPPOSED TO 15 YEARS AS DE CAROLINAS PROPOSED. DO YOU AGREE WITH HER RECOMMENDATION?**

A. No, I do not agree. Given the pace of technology advancement, the trend across the industry is shorter depreciation schedules from a regulatory and accounting perspective, as systems such as AMI are more of a computer based technology. In addition, the Commissions in Indiana, Kentucky, Ohio and Florida all utilize 15-year depreciation lives for the Duke Energy AMI meters deployed in those jurisdictions.

**Q. IN HIS PRE-FILED DIRECT TESTIMONY, EDF WITNESS ALVAREZ AT PAGES 24-29, DISCUSS CONCERNS WITH THE COMPANY'S AMI COST-BENEFIT ANALYSIS. HOW DO YOU RESPOND?**

A. First, the Company's AMI cost-benefit analysis was filed in DE Carolinas' SGTP supplemental filing on May 2, 2017 and again on October 2, 2017 in Docket No. E-100, Sub 147. In past SGTP dockets, the Company has discussed that parties likely have different definitions of a "cost-benefit" analysis, and there is not a standard template that every project related to smart grid technologies follows in completing the evaluation and analysis for determining the business case for a specific technology. Many different factors go into the decisions to invest, or not invest, in any specific technologies or solutions at any specific time. Those decisions follow the same process as any investment made across the utility. As such a cost-benefit analysis is not in and of itself determinative of whether a project will move forward. As I discussed previously, AMI is a foundational investment that enables additional customer convenience, choice, control and transparency. Without the AMI capability, future such customer benefits will not be possible. Public Staff witness Floyd, on page 42 of his testimony regarding his discussion of the AMI cost-benefit, acknowledges that "while helpful and necessary in the decision to replace meters, should not be the sole basis used to justify replacement of the existing AMR meters." Additionally, witness Floyd goes on to say "The Company's commitment to new rate designs, the changing nature of the utility business, and the need to properly identify cost causation and to appropriately price the goods and services provided by the Company, must also be considered. I consider these to be benefits that are not easily quantified in terms of a strict cost-benefit analysis". The Company agrees with Witness Floyd's comments.

Regarding Mr. Alvarez's concerns that DE Carolinas failed to provide sufficient detail to his liking as to future rate options that will be enabled by an AMI project, Company Witness Pirro addresses rate options in his rebuttal testimony. The Company certainly expects that innovative future programs and applications that are not even contemplated at this point in time may be developed as a result of a foundational AMI project. DE Carolinas believes that the Commission's existing SGTP, ratemaking and EE/DSM processes provide opportunity for stakeholder engagement and comment in the development and approval of such programs to maximize customer benefits.

**Q. IN HIS PRE-FILED DIRECT TESTIMONY, EDF WITNESS ALVAREZ AT PAGES 35-36, DISCUSSES THAT THE COMPANY LISTED "PREPAID ADVANTAGE" AS A PROGRAM THE COMPANY PLANS TO OFFER. IS THERE AN UPDATE ON THIS PROGRAM FROM THE COMPANY?**

A. Yes, as noted above in my testimony the Company filed on January 16, 2018 a Prepaid Advantage energy efficiency pilot program in Docket No. E-7, Sub 1167. The Company is excited to offer Prepaid Advantage that witness Alvarez highlights as a program that will drive conservation benefits for customers.

**Q. IN HIS PRE-FILED DIRECT TESTIMONY, EDF WITNESS ALVAREZ AT PAGES 36-37, DISCUSSES USAGE ALERTS, BUT SAYS "THE COMPANY DOES NOT COMMIT TO OFFERING USAGE ALERTS." CAN YOU CLARIFY THIS ASSERTION?**

A. Yes, this assertion by witness Alvarez is confusing. I noted in my direct testimony in this case on page 8 that DE Carolinas has already implemented usage alerts.

**Q. EDF WITNESS ALVAREZ RECOMMENDS THAT COMMISSION REVIEW DE CAROLINAS' AMI PROJECT AS PART OF A NEW GRID MODERNIZATION PROCEEDING. DOES DE CAROLINAS AGREE WITH THE PROPOSAL TO ESTABLISH YET ANOTHER GRID MODERNIZATION DOCKET OR PROCESS TO REVIEW THE AMI PROJECT?**

A. No, DE Carolinas does not believe that a new grid modernization process is needed. The Commission already has a SGTP rule and dockets to review, allow for intervenor investigation and comment, and ultimately accept, modify or reject the Company's SGTP and those of the other utilities. The Company filed its AMI cost-benefit analysis in the DE Carolinas' SGTP supplemental filing on May 2, 2017 and again on October 2, 2017 in Docket No. E-100, Sub 147. In the past, the Commission has sought verified answers to questions they submitted and scheduled presentations, as was done in October 2017, to gain additional information about AMI plans and there is no indication that the Commission does not have the necessary means to review AMI plans under its existing processes. Cost recovery for the Company's AMI program will be subject to the existing robust and transparent rate case process. Accordingly, DE Carolinas does not agree with the proposals to create a duplicative process to review AMI plans.

Q. **ON PAGES 33-35 OF HIS TESTIMONY, NCSEA WITNESS MURRAY ALSO RECOMMENDS A "BRING YOUR OWN DEVICE" OFFERING THAT ALLOWS CUSTOMERS TO CONNECT HOME AREA NETWORKS DIRECTLY TO THE COMPANY'S AMI RADIO. HOW DO YOU RESPOND?**

A. First, smart meter to home area network ("HAN") connections combine two separate security risks. First, the current lack of security within Internet of Things ("IoT") devices, gateways and applications, and second, external connections to critical infrastructure. For both topics, Duke Energy is deliberately and carefully evaluating the associated risk to the reliability of the power grid. Our considerations currently include: (1) research conducted by third parties, (2) compliance with National Institute of Standards and Technology ("NIST") based security standards that federal and state commissions have encouraged the Company to adopt, (3) alignment with recently released security principles related to both topics provided by the Department of Homeland Security ("DHS"), National Security Agency ("NSA") and the Department of Energy ("DOE"). Cyber security threats are of the utmost concern to the Company and for these reasons the Company does not support the bring your own device recommendation by witness Murray at this time.

Second, another concern is support and upgradeability. At this time, if a customer buys a device not known to the Company, DE Carolinas would not be able to provide support to the customer if that device fails or is not able to connect to the meter. If a new security release is made available the Company may push that to the meter. The Company would have no way to test to ensure that that new version that was pushed is compatible with all of the devices that a customer may have purchased. Customer satisfaction would be impacted along with a large increase in call volumes. Again, the Company does not support the "bring your own device" recommendation by witness Murray, unless or until such concerns are addressed.

**Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?**

A. Yes.

BY MR. SOMERS:

Q. Mr. Schneider, have you also prepared summaries of your direct and rebuttal testimony?

A. Yes, I did.

MR. SOMERS: Mr. Chairman, in an effort to move things along, we would ask that those be entered into the record and waive him reading them, unless the Commission would prefer otherwise.

CHAIRMAN FINLEY: Without objection, the Schneider summaries shall be copied into the record as though read orally.

(Whereupon, the summary of the prefiled direct testimony and prefiled rebuttal testimony of Donald Schneider was copied into the record as if given orally from the stand.)

Duke Energy Carolinas
Summary of Rebuttal Testimony of Donald L. Schneider, Jr.
NCUC Docket No. E-7, Sub 1146

The purpose of my rebuttal testimony is to respond to comments and recommendations of Public Staff witnesses Jack Floyd and Roxie McCullar and EDF witness Paul Alvarez regarding DE Carolinas' AMI cost-benefit analysis and explain further how an investment in AMI will increase customer value. In response to concerns about maximizing the benefits of AMI deployment, I discuss how the Company is addressing those concerns. With the capability to record interval usage data, smart meters are a foundational technology that can enable new rate designs, as referenced in Company witness Pirro's rebuttal testimony. This additional data, combined with the new Customer Connect project referenced in Company witness Hunsicker's rebuttal testimony, will provide DE Carolinas with expanded options and flexibility to support enhanced services and rate offerings. As for new payment options, the Company recently filed a Prepaid Advantage energy efficiency pilot program that will allow participants to pay in advance and settle daily for their energy use, rather than being billed after usage has occurred. And as for informational tools that provide more granular and timely data, as I discussed previously, customers with AMI meters have access to detailed information about their hourly and daily usage patterns through the Duke Energy customer portal.

On the issue of opt-out, I join Public Staff witness Floyd who has encouraged the Commission to rule on the AMI opt-out tariff filed by the Company in July 2016. However, I disagree with Public Staff witness Floyd's recommendation that the Company perform additional cost-benefit analyses in its next base rate case. The Commission has the necessary information to determine recovery of costs based on the information DE Carolinas had at the time that the decision to fully deploy AMI meters was made.

On the issue of depreciation, I support the Company's request that new AMI meters receive a 15-year depreciation life instead of the 17-year life recommended by Public Staff witness Roxie McCullar. Given the pace of technology advancement, the trend across the industry is shorter depreciation schedules from a regulatory and accounting perspective for systems, such as AMI, using computer-based technology.

On the issue of a new Grid Modernization proceeding proposed by EDF witness Alvarez, I explain that the current proceeding, combined with DE Carolinas' annual Smart Grid Technology Plan filings, offers the Commission, Public Staff and other interested parties the ability to investigate and comment on the Company's AMI plans without requiring a separate proceeding.

Finally, I respond to NCSEA witness Michael Murray's request that the Commission adopt a "bring your own device" requirement, to allow customers to connect home area networks directly to the Company's AMI radio. Smart meter to home area network connections combine separate security risks that could affect reliability of the power grid. Because cyber security threats are of the utmost concern to the Company, DE Carolinas does not support this proposal.

This concludes the summary of my Rebuttal Testimony.

MR. SOMERS: I want to make sure Mr. Finnigan gets home in time to watch the Musketeers and Bearcats play. With that, Mr. Schneider is available for cross.

MR. FINNIGAN: Much appreciated. Your Honor, may I approach the witness with an exhibit that was marked in Mr. Simpson's cross examination?

CHAIRMAN FINLEY: Yes, you may.

CROSS EXAMINATION BY MR. FINNIGAN:

Q. Mr. Schneider, nice to see you again. We've met before?

A. Yes, we have, John.

Q. And just for the record, I'm John Finnigan, counsel for Environmental Defense Fund. Mr. Schneider, I've placed before you the exhibits from Mr. Simpson's cross examination, and I would like you to turn to Exhibit 2. It's at Tab 2 there. And that's a report on the stimulus bill smart grid pilot projects, and that was the grant from the Department of Energy to Duke to do the smart grid pilots in a few states.

Could you turn to page 2 of 6, as it's marked in the upper right-hand corner?

A. Yes.

Q. And there is a box there in the middle of the page on the right where it references customer engagement pilots?

A. Customer -- I see.

Q. For the Carolinas?

A. Customer enablement pilots?

Q. Yes.

A. Okay.

Q. What are those?

A. Well, I see this is dated back in March of 2015. I'm not familiar with that term, "customer enablement pilots," but I do believe it is in relation to electric -- some electric vehicle pilots that we had back at that time.

Q. Okay.

A. That's about all I know. That term does not look familiar to me.

Q. Okay. Thank you.

A. I don't believe it's related to AMI.

CHAIRMAN FINLEY: Pull the mic around there, Mr. Schneider, so we could hear you.

MR. FINNIGAN: That's all the questions I have about that. Thank you.

And Mr. Chairman, may I approach to have some exhibits marked?

CHAIRMAN FINLEY: Yes, you may.

BY MR. FINNIGAN:

Q. Mr. Schneider, I would like to first ask you about performance metrics.

Would you agree with me that, when a utility does a major project, like AMI, it's good utility practice to have some performance metrics that lay out what the objectives are you that are trying to accomplish, and then allow you to measure your performance against those objectives?

A. Yes, I would agree with that.

Q. And can they also help the Commission to determine whether you're implementing the project in a prudent manner?

A. Yes. Depending on what the metrics are, yes, I would agree.

Q. And did you propose any performance metrics in your testimony in this case?

A. No, we did not.

Q. Could you please turn to the document that's marked as Exhibit EDF Schneider Cross Exam Exhibit 1?

A. Yes. Page 1 of 79?

Q. Yes. Can you identify that as testimony you filed with the Indiana Commission to support an AMI deployment there?

A. Yes, that's correct.

Q. And could you turn to the very last page of that document, page 79 of 79, in the upper right-hand corner at the top of the document?

A. Yes, I'm there.

Q. Can you identify that as performance metrics that you proposed with the AMI deployment in Indiana?

A. Yes, they do look familiar. I can't recall if it was part of our proposal, or part of the negotiation or the stipulation settlement, or I don't recall if we submitted it as proposal or -- but yes, eventually we got to this as a proposed metric.

CHAIRMAN FINLEY: Do you want it marked, Mr. Finnigan? Mr. Finnigan, do you want it marked?

MR. FINNIGAN: Yes. I would like that document marked as EDF Schneider Cross Examination Exhibit 1, the entire exhibit that's at Tab 1.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, EDF Schneider Cross Examination Exhibit No. 1 was marked for identification.)

BY MR. FINNIGAN:

Q. And then please turn to page 24 of 79 of that document.
A. Okay. I'm there.
Q. And let me ask you to take a look, beginning at the sentence that starts at line 11, it says, "Based on experiences in other jurisdictions, in terms of relevant information and ability to collect, Duke Energy Indiana proposes to develop metrics for tracking both the AMI deployment, build metrics, and the AMI benefits packet metrics"; have I read that correctly?
A. Yes, I see that.
Q. So does that refresh your memory that you did propose those as part of your filed --
A. Yes, it does. That's why I wasn't sure if it was in my original testimony or elsewhere. Thank you.
Q. Okay. Now, would you agree to use those same metrics and report those to this Commission on an annual basis as you go forward with the AMI deployment here in Duke Energy Carolinas' territory?
A. Yes. I think we would be willing to work out what the pertinent metrics would be that the Commission and others would be interested in seeing.
Q. Now, if those metrics were pertinent in Indiana, that's what you propose?

A. Yes.
Q. Would you be willing to report on the same metrics here for this Commission?
A. Sure. Yes, sir.
Q. Now, let's change the subject to home energy monitors.
Do you agree that an in-home display, or a home energy monitor, is an important tool to give customers greater control over their energy usage?
A. I think it's one of many tools that can give customers a view -- a better view into their interval usage data. I think, also, what we provide already today, as part of our AMI deployment, we have available on our customer portal the customer usage information in hourly increments for our customers to be able to go out and view at any time. So I think that's another way. I would say the in-home management is the most important form -- or in-home display is the most important form, as you stated, I believe.
Q. I didn't say it was the most important. I just said an important.
A. Oh, an important, yeah. I would say it is one. I don't know that it's the most important.
Q. Okay. Now, has Duke tested any home energy

monitors?

A. I can't recall if in years past we have, but most recently, we are working on or have worked on a pilot -- energy usage pilot, I believe, in the Carolinas is where we have done that.

Q. For home energy monitors?

A. Yes. It's -- well, it's an app, so you use your phone as the monitor.

Q. Is this referred to as the Powerley device?

A. Yes, that's it.

Q. It's manufactured by Detroit Edison?

A. I do not know that.

Q. And it's a bridge -- there is a device called the Energy Bridge that's in the customer's home, and that allows the energy usage data to be transmitted to the customer's phone or a computer tablet?

A. That's my understanding, yes.

Q. Mr. Fountain talks about it in his testimony?

A. Yes. Yes, he does.

Q. Now, I wanted to ask you how the information is transmitted over this energy bridge to the customer's phone and computer tablet. The home energy monitor connects to the smart meter over the customer's personal Wi-Fi network; is that right?

A. That's my understanding, yes. The customer has to have an Internet service provider and Wi-Fi.

Q. Okay. And the Company is in the process of developing a pilot program for these devices, according to Mr. Fountain?

A. That's my understanding, yes.

Q. Okay. Now, under this program, the customer would only be able to use these kind of devices that are supplied by Duke; is that right?

A. That's my understanding for this pilot, yes.

Q. And they would only be able to get the information that Duke wants them to get?

A. That I don't know.

Q. Would you know whether third parties could transmit information to customers using these devices?

A. I do not know enough about the pilot to answer that.

Q. Now, in your rebuttal testimony, you referred to some testimony that Mr. Murray filed about a bring-your-own-device program?

A. Yes, I recall.

Q. And his basic recommendation was that customers should be allowed to bring their own home energy monitors, to select the ones that they wanted to use for themselves in their home, and you recommended against that for a number of reasons?

A. That's correct.

Q. And this Powerley Energy Bridge that's in the home, the end result would be customers can't select their own monitors; they would be forced to use only the one that Duke supplies?

A. Well, again, the monitor is either your laptop or a tablet. So in terms of a definition of a monitor, I would say that's incorrect.

Q. Okay. Let's -- I'm sorry. I used the wrong term. I meant bridge, the energy bridge.

The customers would be forced to use the energy bridge that Duke provides and wouldn't be able to use their own home energy monitors?

A. So when you say "bridge," so there is a, what I would call, a black box device that we do provide to that customer in order for them to be able to use their own devices as display monitors.

Q. And that goes in their home and connects with their Wi-Fi?

A. That's correct.

Q. Now, are you aware that, traditionally, the utility's monopoly service ends at the point of the meter?

A. Yes.

Q. So what you are proposing in this pilot is to go beyond that and extend the monopoly into the customer's home?

A. I don't know how to answer that question, I mean, other than the fact that we are providing that black box to the customer.

Q. And you're not -- you're recommending against them being allowed to get their own monitors?

A. Well, at this time, we are, because we have some security concerns, because any device that a customer would bring, there is a couple of concerns around how there is an external connection into our critical grid structure. And when I talk with our IT security, cyber security experts, they've got grave concern about that without looking into it further. So based on what they know today about some of the security issues with the Internet of these type of devices, you know, they are willing to continue to look at it, but today, to say that we would commit to something, a bring-your-own-device program, they are not comfortable with it.

The other part is, you know, as we constantly provide security updates to our systems, as well as the programs on the meters and everything, you know, we're not sure if that -- those updates -- those security patches, updates, would be compatible with a customer's in-home device. So, you know, there could be times where we push out an update, and all of a sudden the customer's device doesn't work. So we don't want to be in a position where customers are spending money on something, and we can't ensure it's going to always work.

Q. What is your understanding of how a home energy monitor would interface with the smart meter? Would it receive the data via the customer's personal Wi-Fi network?

A. So the black box device receives the customer's interval usage data from the meter via what they call a ZigBee radio. So it's a radial RF frequency radio built into the meter that would provide that information to that black box device.

Q. Okay. And then isn't that the same way the home energy monitor would work?

A. It is, yes.

Q. Okay. So on the Powerley program, you let the customer use any phone they want, any customer tablet they want, and it's just getting information from that ZigBee radio that's in the smart meter, and a home energy monitor does the same thing, right?

A. Yes, but we have got -- we've got control over that black box that I talk about. We know what that device is, we know what it does.

Q. Okay. You have tested it on your system?

A. Yes. We have already started the pilot, yes.

Q. Okay. Now, if a customer wanted to use their own home energy monitor device, as long as you first tested it on your system, would that address any concerns you would have about cyber security and security of the grid, as long as you had an opportunity to test that brand first?

A. Well, yeah. So then you get into, you know, do we recommend just certain brands, or do we test all brands out on the market to truly let the customer -- you know, so you get into a pretty costly endeavor there to try to decide which ones we would recommend or test. But I would say that, you know, we commit to continuing to look at those devices, in general -- not any specific manufacturer or models, but looking at those devices, in general, to see if we could get past this cyber security concern.

Q. Okay. And are you aware that there are other utilities that do have these bring-your-own-device programs that are up and running now?

A. Yes. There are some that I have heard of, yes.

Q. Okay. Now, please take a look at the document that is at Tab 2, and I would like to have that marked as EDF Schneider Cross Exam Exhibit 2.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, EDF Schneider Cross Examination Exhibit No. 2 was marked for identification.)

BY MR. FINNIGAN:

Q. And I will represent to you that this is from the Pacific Gas and Electric website, and it's a bring-your-own-device protocol that they use. It's four steps that the customer has to follow, and includes utility testing of the device.

In light of the Commission's order that came out recently in the smart grid technology plan case -- I'm not gonna ask you any questions about this. I'm not gonna ask that this be introduced into evidence in this proceeding, but when we convene at a later date to work through these issues, as Ms. Hunsicker was talking about, if you would just -- if we could discuss it at that time.

A. Yeah. I'm sure that's possible. Again, I haven't looked at the details of the order to see what we are ordered to discuss.

Q. Now, I want to ask you a couple of questions about the Ohio AMI deployment.

When did Duke initially deploy AMI meters in Ohio?

A. We started in, I believe, the late 2007 or early 2008 time frame.

Q. Okay. When was that finished?

A. 2014, if I recall.

Q. Okay. And, to your knowledge, was there any opportunity for stakeholder input and engagement with interested parties before that process began?

A. There was a collaborative group with the Public Staff and other parties that went on throughout that deployment. I wasn't a part of them, but I am aware they were taking place.

Q. Okay. But even though there was some engagement there, did you have an opportunity to engage with the retail electric suppliers to determine what needs they had for data regarding customer usage from those AMI meters?

A. Yes. To my knowledge, they were part of that collaborative.

Q. But isn't it true that, since the date that those meters were deployed, they have complained that Duke has not supplied them with the information they need to build time-of-use rate plans?

A. Yes. And so there are several issues that are around that. Mainly, it's that we have all the residential meters into a very early version of our meter data management system. And Oracle -- during that deployment, Oracle came out with a new version that offered some efficiencies and enhancements. So we moved to that after our deployment. And so the meters that are in the new version have that capability. The meters in the old version do not. So there is a costly effort to transfer those meters from the old version to the new version, and I know there has been a lot of discussion over who bears that cost. Is it the retail electric suppliers or is it the Duke ratepayers?

Q. That cost is about $165 million?

A. I don't recall what it is.

Q. Over $100 million?

A. I don't recall.

Q. And as we sit here today, that complaint about data access still has not been resolved?

A. I know there is parties that are still working on it, yes.

Q. Now, I'd like to change the topic and go back to these displays, like the Powerley display that we talked about with this energy bridge and home energy monitors, and I just want to ask whether Duke has any information about how much a customer can save on their bill if they do have access to their energy usage data, on a real-time or near real-time basis?

A. I can't state the exact studies, but I know there is some EPRI studies out there back in the 2008 time frame I believe, that talks about, you know, the different methods of receiving that information and what they have seen, you know, in some utilities, as far as reduction in customer usage. So the first one was just having the data -- the interval data available for customers to go out and see, and thereby change their usage habits, the number was in the 5- to 10-percent range. And then there is a slight jump, if you go to what you are referring to as the display, a home energy management system with just a display in the home, as opposed to going, you know, into our portal and looking at it, but having it right there in the display, I think the numbers went from 5 to 10 to 8 to 12 or something, that's the best I can recall.

Q. And you're familiar with Envision Charlotte?

A. Vaguely, yes.

Q. And just tell us, generally, what that is.

A. So my understanding is it started out in downtown Charlotte with some of the larger commercial buildings in an effort to drive energy efficiency in those buildings by installing devices and monitors in those buildings to, kind of, start some competition, if you would, amongst the different large commercial buildings in trying to see some energy efficiency savings.

Q. And as a result of having those monitors in those buildings, and with the behavioral programs that went along with that, the Company developed a goal that they would try to save 20 percent on their electricity bills; is that correct?

A. I don't remember the exact number.

Q. Could you please turn to Tab 3 -- or I'm sorry, Tab 4.

MR. FINNIGAN: And I would ask that that document be marked as EDF Schneider Cross Exam

Exhibit 4.

BY MR. FINNIGAN:

Q. And that's a document from Duke Energy that explains a little bit about Envision Charlotte, right? Do you see that?

A. Yes, I'm there.

CHAIRMAN FINLEY: We will mark it 4.

(Whereupon, EDF Schneider Cross Examination Exhibit No. 4 was marked for identification.)

BY MR. FINNIGAN:

Q. Now, the second full paragraph -- I'm not gonna read it, but just the last sentence says, "The goal is to reduce energy use by up to 20 percent by 2016," right?

A. Yes, I see that.

Q. Now, let me ask you to take a look at Tab 3.

MR. FINNIGAN: And I would ask that that document be marked as EDF Schneider Cross Exam Exhibit 3.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, EDF Schneider Cross Examination Exhibit No. 3 was marked for identification.)

BY MR. FINNIGAN:
Q. And that's the Company's May 5, 2017, SGTP filing with the Commission?
A. Yes. Yes, it is.
Q. And do you review those as part of your work for -- with the AMI project?
A. I usually do have a chance to look them over, yes.
Q. Let me ask you to take a look at page 3 of 12, and let me know when you are there.
A. Okay. I'm there.
Q. In the upper right-hand corner, the --
A. Yes.
Q. And are you there?
A. Yes, I am.
Q. Do you see about in the middle of the page a heading that says "DEC AMI Full-Scale Deployment"?
A. Yes. You have it so nicely highlighted for me.
Q. Taking the Chair's words to heart to speed it up. That talks about AMI being the foundational investment that will enable enhanced customer solutions, and then talks about what those are.
And would those enhanced customer solutions

that are enabled by AMI include things like time-of-use rate plans, or home energy monitors, or the Powerley bridge, things like that; that's what we mean when we talk about enhanced customer solutions?

A. Yes, it is.

Q. Now --

A. That's a few of them.

Q. Okay. Those are examples?

A. Yes.

Q. Now, please go to the next page, 4 of 12, last two lines at the bottom, and there it says, "Therefore, the ability to offer the enhanced basic services and programs, as detailed above, along with improvements in customer satisfaction, are some of the nonquantifiable benefits further supporting the Company's decision to move forward with a full-scale deployment of AMI"; is that --

A. I see that, yes.

Q. -- nonquantifiable.

Now, have you heard of something called the Prius effect?

A. Yes, I have.

Q. The Prius effect is something that happened when Prius cars went on the market, and what it means is that, when the drivers got to see how much gas they were saving because of the display on their car when it was operating under battery or on electricity, they saved even more gas than what the developers expected; is that right?

A. That's correct. Yes, that's what I understand.

Q. And the same thing applies to electricity usage, that if a customer has a home energy monitor in their home, they could see how much electricity they are using, then they can save even more electricity, and that's likely 8 to 12 percent reported by EPRI, or the 20 percent goal for Envision Charlotte; that's the Prius effect as it applies to the electricity industry?

A. That's correct.

Q. Okay. And in the cost-benefit study that DEC did in this case for the AMI deployment, did you quantify the Prius effect?

A. I don't believe we did.

Q. Okay. But you --

A. That solely is a customer benefit.

Q. Okay. You have quantified that for other commissions where you have proposed to do AMI?

A. Yes, we did.

Q. Okay. So go back to Exhibit 1, and please take a look at page 79, the last page that we were looking for before, those performance metrics, and then about two-thirds of the way down on that page, that's one of the metrics that you are gonna quantify is, how much savings customers are getting by having access to these displays, this Prius effect; that's one of those performance metrics, isn't it?

A. Yeah. So this is a nonfinancial metric where we were tracking number of customers who could view internal usage on the portal, and the number of different customers viewing interval usage data from AMI meter on the customer portal.

Q. Okay. And then please turn to page 70 of 79.

A. I'm there.

Q. Okay. And what is that?

A. This is our detailed AMI costs and benefits from the Indiana AMI business case.

Q. Okay. And go to the very bottom of that chart there where it says "total benefits." Two lines up from the bottom you have got customer feedback, or Prius effect, and the total savings there is $125 million over a 20-year period?

A. Yes, I see that.

Q. And that's -- and if you look at the next line down, total customer savings, total customer savings over the same period are $366 million?

A. Yes, I see that. I'm not sure what that number -- what that number represents, though.

Q. Wouldn't it be the total of all those items added up?

A. Well, there is total benefits of $642 million, so I'm not sure what the $336 million total -- what items total to the $336 million.

Q. Okay. Well, in any event, the $125 million savings from the Prius effect is a significant component of the total customer savings?

A. Yes. Again, not -- I would have to figure out where that $336 million, what items we were considering at that time as customer savings.

Q. Okay. Now, please turn to Tab 5 of that document. This is the last one I want to ask you about.

MR. FINNIGAN: I would like to have this marked as EDF Schneider Cross Exam Exhibit 5.

CHAIRMAN FINLEY: Shall be so marked.

(Whereupon, EDF Schneider Cross Examination Exhibit No. 5 was marked for identification.)

BY MR. FINNIGAN:

Q. Could you identify this, Mr. Schneider, as testimony filed with the Kentucky Commission to support an AMI deployment down there?

A. Yes, it is, for a CPC and for AMI.

Q. Now, please turn to page 97 of that Document, 97 of 102.

A. Yes, I'm there.

Q. Now, what that shows at the very bottom of the page, is there is a category "customer savings," and the entire customer savings are the Prius effect, either from the electric or the gas service?

A. Correct.

Q. That's a combined utility gas and electric at the time?

A. That's correct.

Q. Okay. And that comprises the entire category of customer savings?

A. Yes, it does.

Q. And then if you would please turn to page 90 of 102, and let me know when you are there.

A. Yes, I'm there.

Q. And this is your cost-benefit study that you filed with the Kentucky Commission, and about two-thirds of the way down, under the benefits category, it shows customer savings, which we established is comprised of the Prius effect, and that is $20 million?

A. Yes, that's correct, marked confidential.

Q. Well, I got this from the Kentucky Commission website.

A. Okay. Got you.

Q. So -- and that's out of a total benefits of $114 million?

A. That's correct.

MR. FINNIGAN: That's all the questions I have today, Mr. Chairman. Thank you, Mr. Schneider. I would like to move for admission of the EDF Cross Exhibits 1 through --

CHAIRMAN FINLEY: Hold that motion for a few minutes, and we will address it in a little while.

MR. FINNIGAN: And then withdrawing that Item Number 2.

CHAIRMAN FINLEY: Okay.

CROSS EXAMINATION BY MR. SMITH:

Q. Good afternoon, Mr. Schneider. My name is

Ben Smith, and I'm here on behalf of the North Carolina Sustainable Energy Association. Today I'm going to be asking you some questions about the AMI meters, as you were already asked by Mr. Finnigan, and the Company's implementation of them. I'm gonna start off with a little bit of background.

When did you manage your first AMI project?

A. I started in September of 2008.

Q. And where was that project located at?

A. In Duke Energy Ohio.

Q. And how many Duke Energy legacy jurisdictions, I believe is how you referred to them, have you assisted or oversaw the implementation of AMI devices in?

A. Duke Energy Ohio, Duke Energy Kentucky, Duke Energy Indiana, Duke Energy Carolinas.

Q. And are these all AMI meters the same type of meter that are currently being proposed in this matter?

A. Duke Energy Ohio we started with a different manufacturer, different AMI solution.

Q. Is that the Echelon meter?

A. Yes, it is.

Q. Do -- and in terms of -- this is more of a jurisdictional question.

Do the smart readers in the different areas, are they adjusted in any way to read different information by jurisdiction, according to legislative requirements, or laws, or rules, or anything like that?

A. Yeah. So the intervals that we collect data are driven, for each jurisdiction, based off of tariff. So -- and it's really the demand. So if a state requires a 15-minute demand or a 30-minute demand, that's how we program those meters to collect data.

Q. Okay. And what is North Carolina's tariff on that; do you know?

A. I believe it's 30 minutes.

Q. Okay. How about data storage; is that any different across jurisdiction due to rules, statutes?

A. Not that I'm aware of.

Q. Okay. I want to talk about the actual meter that is going to be implemented, I believe.

CHAIRMAN FINLEY: I know it's late in the day, but everybody speak up. You are going to put us all to sleep if you don't be careful.

BY MR. SMITH:

Q. The Itron OpenWay CENTRON, is that the meter that's going to be used for that?

A. That is the AMI meter, yes.

Q. Okay. Do you know when this meter was released for sale to the public?

A. I do not know the date.

Q. Subject to check, would you agree that fourth quarter 2009 might be accurate?

A. That sounds about right, yes.

Q. Okay. And would you classify this meter as state-of-the-art technology?

A. Yes, I would.

Q. Okay. What are the advantages over this meter versus the prior AMR meter?

A. Well, there are several advantages. One, obviously we no longer have to drive around to collect the reads from the AMR meter. The meters have a built-in disconnect so we can remotely disconnect and reconnect customers, instead of rolling trucks. Customers no longer have to have appointments. The interval reads, themselves, is a benefit over the top of the AMR meters. And the other thing is we can get alarms and alerts from the AMI meters. The AMI meters are -- it's a two-way communication device, so we can send data to it to send commands for disconnect, reconnect, as well as sending program updates, those sort of things. So those are the main benefits, and then, of course, there is all the other things that can be enabled through the foundation of AMI in regards to customer -- enhanced customer services, like pick your due date, prepay advantage, you know, just like John was saying, customers having usage data available to them and so on.

Q. And that -- are all the those benefits going to be available immediately upon installation in a customer's --

A. We are still -- as I mentioned, we are still working on a pilot, as far as customer information display. There is -- there was a prepay advantage filing that just took place in DEC a few -- a month or so ago. So I think, yeah, everything I mentioned is basically available today.

Q. Is the AMI meter capable of customer data storage?

A. The meter, itself?

Q. Yes.

A. No. Customer data?

Q. Storage, yes.

A. Energy usage data?

Q. Yes.

A. Yes. I'm sorry. Yeah, usage data does store in the meter.

Q. If I say "data storage," I am referring to energy usage data, but I will try and use that terminology throughout.

A. Okay.

Q. All right. I am going to move to data management -- energy usage data management.

What energy data is specifically gathered by the AMI machines?

A. Kilowatt-hour in and kilowatt-hour out. And we are also collecting voltage data.

Q. So that includes individual household peaks?

A. Well, it collects -- it collects that data, the kilowatt-hours in and out, every 15-minute or 30-minute interval.

CHAIRMAN FINLEY: Individual household? What did you say, please? Individual?

MR. SMITH: I'm sorry?

CHAIRMAN FINLEY: Individual household what?

MR. SMITH: Individual household peaks.

CHAIRMAN FINLEY: Peaks, okay.

BY MR. SMITH:

Q. Do the AMI meters allow for information, such as appliances being used or whether an electric vehicle is plugged in at the time?

A. Not -- I mean, you can't specifically see that. It's just a whole house usage meter.

Q. Is there a standard for the Company protocol for energy data usage collection, as in where the data goes, how it's secured, who has access to it, and any indication to the customer whether that has been collected?

A. I'm not aware.

Q. Okay. I think you just said -- and I'm just looking for some clarity here -- the interval collections on the AMI meters, are they going to be at 15 minutes or 30 minutes?

A. For DEC, I'm pretty sure it's 30 minutes.

Q. But the customer portal allows for one-hour interval review by customers on the website, correct?

A. That's right. They could see hourly interval data.

Q. Is there any reason for the disparity between 30 minutes?

A. Well, again, when we set that up years ago, we knew that, you know, all our jurisdictions were different in terms of what the collection interval was going to be, so we just chose to standardize on the hourly interval to provide to the customers.

Q. And is that portal still standardized across all Duke jurisdictions, where it's an hour in Ohio, Kentucky?

A. Yes, it is.

Q. Okay. Would you agree that AMI implementation is part of the Company's modernization efforts?

A. In general, yes.

Q. However, AMI cost recovery is not part of the GRR, the grid resiliency rider?

A. That's correct.

Q. How are the AMI costs being recovered?

A. We are seeking recovery for part of the cost in this case, and then we would seek the rest of the cost in a future rate case.

Q. Okay. And does it -- do you know if it's through a basic fixed charge, the basic facility charge I believe it's called, or is it through the --

A. I can't answer that. That would probably be more Witness McManeus.

Q. Okay. Can you explain to me how the AMI meters are going to interact with the customer connect program once it's implemented?

A. Yeah. So there are both -- there are two stand-alone programs, but the they kind of have to live together in some sense, in that the AMI is a foundational solution which provides additional customer benefits that we talked about, customer solutions. Some of those customer solutions, like some dynamic pricing rates and those sort of things, do require a use of a more modern customer information system that we are proposing.

Q. Move ahead on that then.

Isn't it correct that the goals of the Company through implementation of the AMI smart meters, one of the goals is to create new, inventive rate designs?

A. Again, AMI is a foundational platform that allows us to do those sorts of things. I wouldn't say that outcome is a goal of our AMI deployment.

Q. Could you give me -- and I apologize if you've said this already, but what would you say the goal is, if you could give the elevator speech goal for the AMI deployment?

A. The goal is to deploy the foundational AMI solution so that we could enable additional customer

benefits and customer programs.
Q. So rate design -- innovative rate design might be a customer benefit as a result?
A. That would be a customer program, yes.
Q. Do you anticipate any new rate designs in 2018 as a result of the AMI implementation in the DEC territory?
A. That would be better suited -- question would be better suited for Witness Pirro.
Q. All right. On page 16 of your rebuttal testimony, you state that the Company opposed connection to a home area network, and this is set in the NCSEA Murray testimony; isn't that correct?
A. Yes, it is.
Q. Can you explain exactly the basis of your opposition for that? And I apologize. I know this runs a little bit over what we were just talking about, but I was hoping you could just expand a little bit on what the opposition is?
A. I think the main opposition, at this point, is the security -- cyber security issue that I spoke to.
Q. And that's what I thought you were going to get to. You cited, I believe on the same page of your

rebuttal, recent release security principles from the Department of Homeland Security, National Security Agency, and the Department of Energy as guiding principles in the cyber security that you are referencing, and part of the basis for the opposition.

Can you tell me where the Department of Homeland Security, National Security Agency, or the Department of Energy released principles related to data storage or collection from smart meters?

A. Yeah. I'm not that well versed on those. I mean, this is just information that I gathered from our cyber security experts.

Q. Okay. So another person who works in the cyber security team at Duke, was it at DEBS or at DEC?

A. It would be a DEBS employee.

Q. Okay, DEBS. And they told you these are the protocol, and they found it through these different agencies?

A. That's correct.

Q. Okay. But you have no -- well, is it your position that DHS, NSA, or DOE specifically oppose home area network connections in conjunction with utility implementation of AMI?

A. Did you say that they oppose?

Q. Yes.
A. No, I don't think that's the case.
Q. Okay. And you also mentioned the Company has reviewed third-party research in determining that it opposes such home area network AMI connections.
What third parties and what type of research are you talking about?
A. Can you point me to that?
Q. Yes, I can. In the line 9 through 11 -- I'm sorry, 11 through 12, "Our considerations currently include: one, research conducted by" --
A. What page are you on?
Q. 16 still.
A. 16?
Q. Of your rebuttal testimony, yes.
A. There is only eight lines on page 16.
Q. I'm not sure -- the question is on pages 33 through 35 in his testimony, NCSEA, that's the question.
A. Can you read the question, because I think there was two different versions of my testimony. I may not have the right version in front of me.
Q. Okay.
CHAIRMAN FINLEY: First time that has

happened, but go right ahead.
BY MR. SMITH:
Q. "On pages 33 through 35 of his testimony, NCSEA Witness Murray also recommends a, quote, bring your own device, end quote, offering that allows customers to connect home area networks directly to the company's AMI radio. How do you respond?"
And without going through your full response, you do go to say, "Our considerations currently include: one, research conducted by third parties," and I was just wondering what third parties those were.
A. (Witness peruses document.)
Okay. Yeah. That's -- again, that's information I got from our cyber security experts. I'm not sure what research they are referring to.
Q. Okay. I'd like you also to -- excuse me. On page 5 of your rebuttal testimony, you -- near the end, you state, "A full deployment of AMI is expected to further enhance revenue loss identification abilities."
What exactly do you mean by that?
A. What line?
Q. This is lines 16, 17, and 18.
A. (Witness peruses document.)
Okay. Could you read it again, because

again, I think the line numbers are off on this copy I have got for some reason.

Q. Sure. You testify, "A full deployment of AMI is expected to further enhance revenue loss identification abilities."

A. Is that following the question that starts out, "Public Staff Witness Floyd"? Is that the question?

Q. It's starts out with, "In his -- what testimony on page 42 Public Staff Witness Floyd states, I am generally supportive."

CHAIRMAN FINLEY: Somebody maybe better get Mr. Schneider the correct copy of his testimony there.

COMMISSIONER PATTERSON: And rebuttal.

THE WITNESS: Okay. Could you give me the page number again? I'm sorry.

BY MR. SMITH:

Q. Yes, I can. Page 5, and those are lines 16, 17, and 18.

A. (Witness peruses document.)

Where it starts out, "Analytics capabilities for revenue protection"?

Q. Ir begins, "A full deployment of AMI is expected to further enhance revenue loss identification abilities." It's page 5 of your rebuttal.

A. Okay. Yeah. "A full deployment of AMI is expected to further enhance the revenue loss." Yes, uh-huh.

Q. I was just hoping you would expand on what you meant by that.

A. Yeah. So the revenue loss is around theft, as well as slowed meters, incorrect meter installations for the larger transformer rated meters, all, sort of, what we call nontechnical losses that AMI allows us to better detect.

Q. Okay. And when you talk about theft, is there any -- actually, scratch that question. Okay. I want to go over just a few more things, and then I will be finished.

The AMI meters, has the Company done any outreach to customers to see what they wanted in a smart meter?

A. Well, I don't know that -- I think we did in some other jurisdictions. We held focus groups and surveys around listing out some of the programs that we were planning to offer with AMI and -- or that would be available through AMI, and questions were around, you know, would you -- how likely would you be to sign up for such a program?

Q. And was third-party data access part of that customer outreach?

A. I don't really recall.

Q. Okay. So with regards to the new AMI meters being implemented, they have, I believe, a 15-year depreciation life is what Duke is asking for; is that correct?

A. That's correct.

Q. Is it also correct to say that they are -- fully functional abilities will not be completely implemented until the customer connect is rolled out at the end of 2022, or during the year 2022?

A. Well, the full capabilities of AMI, itself, as a solution, will be. Some of the products and services that it enables will not be.

Q. So Duke won't be able to utilize them until customer connect is rolled out in 2022?

A. In the example of dynamic pricing, yes.

Q. So for time-of-use rate designs and new rate designs like that, you would have to wait until after customer connect is rolled out in 2022?

A. That's right. I think Retha -- or

Witness Hunsicker talks about that in her testimony.

Q. So by the time -- actually, scratch that. So with the new AMI meters, I want to talk about some of their capabilities very quick before I finish.

Are the new AMI equipped to handle integration of net metering?

A. Yes, they are.

Q. Are they equipped to integrate -- excuse me. Are they equipped to -- for integrated distributed generation?

A. I don't know what is meant by "are they equipped."

Q. Local generation, solar, different types of --

A. So again, as the AMI solution, the data we get from the meters helps enable some distributed energy renewables.

Q. So they are equipped to take on renewables is what my question is.

A. They provide the data.

Q. Are they equipped -- and I realize we have been over this, and they are not currently planned to -- are they equipped to allow third-party data access?

A. Again, it's not the meters themselves that are equipped with anything to do that. It's all about the data and how the data is released.

Q. But if the data goes through -- and I'm talking about, again, the energy data goes through the meters and then it is disbursed somehow, to maybe the customer connect program or maybe to a third party, the meter, itself, is allowable to have a third party connect to it?

A. A third party to connect to the meter?

Q. I'm saying that the meter could disburse the same way that it does to customer connect theoretically, it could to a third party who is looking through that --

A. So, again, the meter provides data that would be housed and available for third party access?

Q. Okay. Is it equipped to integrate microgrid technologies?

A. Again, that line of questioning does not make a lot of sense. They are not -- the meters, themselves aren't equipped to do that stuff. The meters, themselves, are equipped to provide information that's related to those.

Q. And I guess what I'm not trying to do here isn't -- I'm not trying to put down the meter or try and take away from its abilities. I just want to see if it's capable of integrating with those technologies going forward.

A. It's capable to provide information that will allow that, yes.

Q. And is it capable to provide information that will be something that will be -- is it capable to integrate and provide information regarding energy storage -- excuse me -- energy storage?

A. Again, the meter is not capable to integrate, but the meter is capable to provide information that will assist with energy storage.

MR. SMITH: I have no further questions.

CHAIRMAN FINLEY: Let's see if we could finish Mr. Schneider here before the day is out.

CROSS EXAMINATION BY MS. ROSENTHAL:

Q. I will try and make this snappy. Hi. Sherri Zann Rosenthal, City of Durham.

The meter is providing two-way communication; is that wired communication or is it through Wi-Fi or cellular?

A. It's wireless through RF 900 megahertz frequency for the majority of the meters. We do have some meters that are -- have a cellular modem in them, so we would provide that or receive that data back -- or the two-way communications to that meter would be via cellular.

Q. And are you aware -- and I would guess that you are -- that the other states you have operated in are no different than our state, that there is some customers who do not want cellular or other near-microwave communication in or around their house, to the extent that they can avoid it?

A. Yes, I am aware of that.

Q. And did you know that North Carolina has a docket to determine whether, for these customers who want to forego the AMI meter, if there should be an additional charge for reading that meter?

MR. SOMERS: Mr. Chairman, we will stipulate that there is a docket open on the AMI opt-out, and questions could be asked in that docket.

BY MS. ROSENTHAL:

Q. Okay. Then I will ask either of you.

Has data from the other states, and what they may have determined an appropriate charge to be, been provided in that other docket?

A. I'm not familiar.
Q. If it has not, could we have the data on other states and what they have done on this issue?
MR. SOMERS: Mr. Chairman, I am going to object to the continued attempts to conduct discovery on the stand. I don't think it's appropriate. There is another docket for that, and the City of Durham can intervene and ask whatever data request it wants to in that docket.
CHAIRMAN FINLEY: All right. Ms. Rosenthal, you have been invited to ask your questions in that docket.
MS. ROSENTHAL: Thank you so much, sir. I so appreciate the welcome invitation. That's all.
CHAIRMAN FINLEY: Ms. Thompson?
CROSS EXAMINATION BY MS. THOMPSON:
Q. Good afternoon, Mr. Schneider.
So advanced metering infrastructure, AMI, you say that that's a foundational investment that enables additional customer convenience, choice control, and transparency, correct?
A. Correct, yes.
Q. And with regard to the control prong of that

catchphrase, AMI can help customers make more informed choices about their energy use?

A. Yes, they can.

Q. And you would agree that smart meters would enable customer access to granular and timely data about their energy usage that give them -- that help them to make more informed choices about how they use energy?

A. That's correct, yes.

Q. Now, customers won't be able to use their energy usage data to reduce the basic facilities charge, will they?

A. Not to my knowledge, no.

Q. And that's because that's a fixed charge on the bill that doesn't vary according to usage, right?

A. That's my understanding, yes.

Q. Okay. You also say that smart meters can enable new rate designs?

A. Correct.

Q. And you point to the existing smart grid technology plan, ratemaking, and energy efficiency demand-side management processes at the right proceedings to establish those future rate options that would be enabled by AMI?

A. That sounds correct, yes.

Q. Okay. Now, the smart grid technology plans -- I will come back to that in a moment, but as far as the ratemaking processes that you are referring to, are you referring to a general rate case such as this one?

A. For time-of-use rates?

Q. I'm not even specifically asking about time-of-use rates. You just made a pretty generic statement in your testimony about the future rate options enabled by AMI.

A. Yes. I'm speaking about dynamic pricing, in general, which would include time-of-use rates, and I believe Witness Pirro talks more to that in his testimony.

Q. Okay. And in developing the rates for this case, and I guess for future cases, does the Company typically solicit stakeholder input in developing those proposed rates?

A. That would be, again, a question for Witness Pirro.

Q. The other -- one of the other processes that you say are existing and adequate was the energy efficiency demand-side management rider proceedings, correct?

A. Yes.

Q. And is it your testimony that it would be appropriate for the Commission to establish base rate tariffs that would be enabled by AMI in those proceedings?

A. Again, that would be -- that's outside of my area of expertise, so probably Witness Pirro.

Q. All right. Now, you also say that a separate proceeding to review the Company's grid modernization and AMI plans is not needed, right?

A. That's correct.

Q. And you point to the smart grid technology plan rule, and the process under that rule is adequate?

A. That's correct.

Q. And there you are referring to the Commission Rule R8-60.1; is that right?

A. Subject to check, yes.

Q. Okay. And does that rule provide for hearings on the smart grid technology plans?

A. I am not intimately familiar with the rule, itself.

Q. Okay. So you are not familiar with that rule that you referred to in your testimony as providing for an adequate process for reviewing the smart grid technology plans?

A. I'm just not that intimate into the details of the rule, itself. I'm aware of the rule and how we provide our smart grid technology plan on an annual basis that can be reviewed by the Commission and other parties.

Q. All right. So you are aware that there is a comment period in those dockets?

A. Yes, I am aware of that.

Q. Okay. And are you aware of -- going back to -- going back a couple of years, are you aware that the Commission stated, in its November 5, 2015, order approving the initial smart grid technology plans, that the proceedings are intended to be informative, but the Commission doesn't anticipate using them to order utilities to make specific smart grid investments, nor are they a means by which utilities should seek to secure advance prudency reviews of smart grid investments; does that sound right, subject to check?

A. I'm not familiar with that language, but yes, subject to check.

Q. Are you aware that the Company filed -- and this is Duke Carolinas -- filed a smart grid technology plan in October 2016?

A. Yes, I'm aware of that.

Q. And the Company did not mention any plans for deployment of smart meters in that plan, did it?

A. I believe you are incorrect. I believe we did mention --

Q. So it's your testimony --

A. I believe we did mention it in the DEC 2016.

Q. Okay. So are you aware of the Commission's March 29, 2017, order approving the smart grid technology plans?

A. What was the date of that? I'm sorry.

Q. This was March 29, 2017.

A. Again, not intimately familiar, no.

Q. Would you accept, subject to check, that the Commission, in that order, stated it interpreted the omission of any concrete plans for deployment of smart meters in the October 2016 SGTP to mean that the Company had no plans to replace its existing meters with AMI during the following five years?

A. Okay. So what I do recall is that we talked about some of the AMI deployments that we had currently going on, but we, at that point, in that filing, did not -- had not committed to a full-scale AMI deployment, as of October 3rd, '16. We actually made that commitment through our senior management approval and board approval, I believe, in the November -- late November time frame of '16. That's why we filed a supplemental SGTP, and I believe it was in May of '17, to inform the Commission that we had made that decision, just following the filing of the October 3, 2016, SGTP.

Q. That's right about the late 2017 decision to deploy smart meters. So it's your testimony that the Company's supplemental SGTP filing in May of 2017 was not in response to the Commission's March 29th order in which the Commission noted the omission of the Company's plans to deploy smart meters?

A. No. So the 2016 supplemental was just an update, again, to provide the Commission with the fact that we had made the decision to go with a full deployment.

Q. All right. If the Company wants to build a -- let me ask you first. In this case, the Company is seeking to recover about $197 million for smart meter implementation, correct; does that sound about right?

A. Yeah. I don't know the exact number.

Witness McManeus might be able to check that number for you.

Q. Okay. So, hypothetically, if the Company wanted to build a 200 megawatt -- I'm sorry, $200 million power plant, it would have to obtain a certificate of public convenience and necessity, right?

A. Again, that's not my area of expertise, so I can't answer that.

Q. All right. Would you accept that, subject to check, that there was a requirement that the Company obtain a certificate prior to constructing a new power plant?

A. Subject to check, yes.

Q. And we have also agreed that there is no advance prudency review in the smart grid technology plan docket, the way there is if the Company had proposed to build a $200 million power plant, right?

A. Well, I don't know what you mean by a prudency review. Again, the smart grid technology plans are available for all parties to review and comment on.

Q. Okay. Thank you.

MS. THOMPSON: That's all the questions I have. Thank you.

CHAIRMAN FINLEY: Public Staff, do you have a question? Ms. Edmondson?

CROSS EXAMINATION BY MS. EDMONDSON:

Q. Good afternoon, Mr. Schneider. Lucy Edmondson with the Public Staff. I just had a couple of clarifying questions.

You discussed with Mr. Finnigan the benefits of the home energy monitor program, the Prius effect?

A. Yes.

Q. And those benefits are energy savings?

A. Yes, they are.

Q. Am I correct that Duke Energy Carolinas is planning to offer the home energy monitoring program as an energy efficiency program?

A. I'm not aware of that.

Q. So you don't know whether it's gonna collect those through -- the cost through base rates or the DSM-EE rider?

A. So are you -- what are you referring to, the pilot that we talked about?

Q. Right.

A. The Powerley pilot?

Q. Right.

A. Yeah. I'm not familiar with how we will do that. I'm not aware of that.

Q. And the prepay advantage program, that has been filed as an energy efficiency program?

A. Subject to check, I believe you are correct.

Q. And are you aware that, under the DSM-EE mechanism for Duke Energy Carolinas, Duke will receive, as incentive, both its net loss revenues for energy saved and an incentive based on energy savings?

A. I'm not familiar with that rider at all.

Q. So in your cost-benefit analysis you discussed for AMI, did you include the cost or the benefits associated with the prepay --

A. No --

Q. -- program?

A. -- we did not. We didn't have costs or benefits included.

Q. So those would be through the DSM-EE program?

A. Again, I'm not familiar enough to know that.

MS. EDMONDSON: All right. I just wanted to clarify. Thank you.

CHAIRMAN FINLEY: Redirect?

MR. SOMERS: Yes. Thank you, Mr. Chairman.

REDIRECT EXAMINATION BY MR. SOMERS:

Q. Mr. Schneider, both Mr. Finnigan and Ms. Thompson asked you several questions about the smart grid technology plans and Docket Number E-100, Sub 147; do you remember those?

A. Yes, I do.

MR. SOMERS: Chairman, I would ask that the Commission take judicial notice of all the Company's filings and any other intervenor filing and the Commission's orders in that docket from October 3rd, 2016, to present and make those part of the record in this case.

CHAIRMAN FINLEY: All right. Without objection, we will take judicial notice from October of what date?

MR. SOMERS: October 3rd, 2016, which, to clarify, is the date that the Companies', DEC and DEP's, 2016 smart rate technology plans were filed.

CHAIRMAN FINLEY: All right. E-100, Sub 147 shall be allowed.

MR. SOMERS: Thank you.

BY MR. SOMERS:

Q. Ms. Thompson asked you if in the Company's -- and I am referring to Duke Energy Carolinas -- in Duke

Energy Carolinas' 2016 smart rate technology plan filed in October of 2016, she characterized it as the Company didn't mention plans for deploying smart meters; do you remember that?

A. Yes, I do.

Q. And I believe you said she was incorrect?

A. Yes.

Q. Do you have copy of the 2016 smart rate technology plan up there with you?

A. Yes, I do.

Q. If you look at page 20 of that, under section 4, which I will quote to you, says, technologies actively under consideration, end quote?

A. Yes, I see that.

Q. Do you see the second sentence that begins, "In 2016"?

A. Yes.

Q. Would you read that, please?

A. "In 2016, the Company began evaluating the case for continuing with incremental deployments or moving forward with the project to exchange all remaining non-AMI meters." Do you want me to go on?

Q. Read the next sentence.

A. "A full deployment will exchange all

remaining AMR meters and any other non-AMI meters, in scope, with an AMI meter, and scale up the back office systems to integrate the new meters over a planned five-year period. A full deployment of AMI would enable enhanced basic services for customers, as well as new choice, control, and flexibility in energy usage, billing, and program offerings."

Q. So in the 2016 smart grid technology plan, the Company informed the Commission, under the technologies actively under consideration, that a full deployment of AMI was being evaluated; is that correct?

A. That's correct.

Q. And then when did you -- I believe you testified that later that year the Company made the actual decision to deploy after that evaluation was complete; is that correct?

A. That is correct.

Q. And when was that, roughly?

A. I believe it was in November.

Q. Of 2016?

A. Of 2016.

Q. Okay. Ms. Thompson also asked you, and referred to the Commission's March 29, 2017, order which approved the 2016 smart grid technology plans; do you recall that?

A. Yes, I recall that.

Q. And I believe you testified the Company filed an update with the Commission on May the 5th, 2017; is that correct?

A. That's correct.

Q. And that was in response to the Commission's March 29, 2017, order, correct?

A. I don't recall that.

Q. Okay.

A. If it was or not.

Q. All right. Well, the cover letter that I filed speaks for itself; doesn't it?

A. Yes, it does.

Q. All right. So in the -- and Ms. Thompson also asked you about the Commission's order that was issued last week in the smart grid technology plan docket, correct?

A. Correct.

Q. And she asked you about the Commission's holding, which is also in that order, that says the smart grid proceedings are intended to be informative, but they don't approve anything, certainly not cost recovery; is that correct?

A. Subject to check, yes.
Q. In this proceeding is when the Company is asking for cost recovery for its AMI deployment costs in the test period in this case, correct?
A. That is correct.
Q. In the Commission's March 7, 2018, order, which was issued last week, and that was certainly after you filed testimony in this case; is that correct?
A. That's correct.
Q. And you are generally familiar with the Commission's March 7th order, correct?
A. The 2018, March 7th?
Q. Yes, sir.
A. I did glance over it, yes.
Q. Okay. And in the Commission's order, they talked about the cost-benefit analysis that the Company prepared as part of its decision to deploy AMI meters on a full scale throughout DEC, correct?
A. Correct, yes.
Q. And the Commission also asked the Company a series of written questions to which the Company responded over a several-month period in that docket; is that correct?

A. That is correct.

Q. And, in fact, the Commission ordered a presentation from the Company, in this very room, that you presented along with Justin Brown for the Company; is that correct?

A. That is correct.

Q. And what was the purpose of that presentation?

A. To provide a general overall presentation on the AMI solution technology and open it up for questions to the Commission and other parties.

Q. And also in that docket, shortly before that presentation actually took place, the Company filed, on October 6, 2017, extensive, detailed cost information as requested by the Commission; is that correct?

A. That is correct.

Q. And after the presentation that you were one of the two presenters at here in October, I believe it was, the Company was also asked by the Commission to do an updated cost-benefit analysis; is that correct?

A. That is correct.

Q. And that was discussed in some detail in the Commission's March 7, 2018, smart grid order, correct?

A. I do recall seeing that, yes.

Q. Now, do you recall -- when the Commission asked the Company to update its AMI cost-benefit analysis that was subsequently filed in December of 2017, do you recall what it is they asked the Company to change in its assumptions for that cost-benefit analysis?

A. So there were a couple of things that I recall. One was an updated cost on the direct connect meters, but the main one was around adding in the cost to replace the meters based on a 15-year life. So replacing them, you know, 15 years out into the business case.

MS. THOMPSON: Mr. Chairman, I am going to have to object. I'm sorry, I don't know if this is still on. I think it is going quite beyond the scope of the cross.

CHAIRMAN FINLEY: I'm gonna allow it. I think it's relevant.

MR. SOMERS: Thank you, Mr. Chairman.

BY MR. SOMERS:

Q. So, Mr. Schneider, when the Commission asked the Company to update the cost-benefit analysis with those revised assumptions that you just mentioned, did the Company provide that?

A. Yes, we did.

Q. And in providing that, did the Company explain its concerns with that methodology?

A. Yes, we did. We had concerns that we were required to add the cost of replacing the meters in the 15-year time frame, but it was still a 20-year business case, so we were not at -- that business case view is not seeing the full benefit of those replaced meters. So really what should have been a 30-year business case to really see the full -- excuse me, the full benefit of those replaced meters, because in our original case, we did not replace the meters after 15 years, but we did have costs -- ongoing costs based on the meter failure rate, and then after the 15-year life, we backed out the benefits in our original business case. So we feel like that is a more accurate business case view than what we were asked to provide.

Q. And certainly the Company doesn't, in any way, dispute the Commission's authority to ask the Company to produce whatever cost-benefit information it wants; does it?

A. Not at all, no.

Q. And with all due respect to the Commission's request for an updated cost-benefit analysis, did it, essentially, ask the Company to include -- to double the cost, but only include half of the benefits?

A. Basically, that's what it is, yes.

Q. And if you do that kind of analysis, what do you think the results will be?

A. They are more than likely going to come out negative, which indicates it did.

Q. And is that the type of analysis that Duke Energy would ever rely on in making a business decision for something like, and as important as, the full-scale deployment of AMI meters across its territory?

A. No. No, we wouldn't.

Q. You were also asked some questions by, I believe, Mr. Finnigan about AMI deployment in other jurisdictions.

Do you recall those questions? And you were handed a lot of exhibits about that.

A. Yes.

Q. Where does North Carolina stand, in terms of the rest of the nation, as regards the deployment of AMI meters?

A. North Carolina, as a whole, or DEC North Carolina?

Q. Let's start with North Carolina as a whole.

A. So North Carolina, as a whole, to my understanding, all of the co-ops have already deployed AMI for several years, so their customers are seeing those benefits. DEC we're -- for DEC North Carolina, we are about halfway done.

Q. And how does North Carolina compare to other states in the United States, in terms of deployment of AMI meters?

A. Yeah. I would say, in general, we are behind in the other -- from what I have seen from a lot of the other states that have deployed AMI.

Q. Coming back to the cost-benefit analysis that the Commission asked the Company to perform before --

CHAIRMAN FINLEY: I think this is really in the nature of additional direct testimony, so let's wrap it up, if we can.

MR. SOMERS: I will, Mr. Chairman. And I will note that the Commission's smart grid order said that these issues will be decided in this case, and I haven't had a chance to ask my witness about them, since the order was only issued last week, but I will wrap it up.

CHAIRMAN FINLEY: As I said, I think it should have been additional direct testimony, but go ahead.

BY MR. SOMERS:

Q. Mr. Schneider, the additional assumption is that the Company was asked to include in the updated cost-benefit analysis by the Commission.

How does that compare to a cost-benefit analysis that the Company would do in making the decision and seeking a CPCN for a new power plant, for example?

A. Could you repeat the question?

Q. Sure. The way the Commission's order asked the Company to do an updated cost-benefit analysis, it asked the Company to include replacement of all the meters after 15 years. So, essentially, doubling the cost, but not including the benefits beyond that 15-year point.

How does that compare to the way the Company does a business case cost-benefit analysis for a power plant?

A. Yeah. So, again, we wouldn't include the costs -- the replacement cost of a power plant in a business case that we would provide for that situation.

Q. Why not?

A. Well, again, you would have to have the benefits -- you would have to see the benefits from that replacement cost. And so, you know, you are just basically rebuilding a whole other business case again, you know, based on the replacement and the additional benefits you get from that.

MR. SOMERS: Mr. Chairman, thank you.

One last question.

BY MR. SOMERS:

Q. Certainly, the Company respects the Commission's authority to seek whatever information it does, but based upon your judgment and experience, why should this Commission allow the Company to recover the costs of its full-scale deployment of AMI meters as included in the test period of this case?

A. Well, because, I think, again, the original business case we submitted was a sound business case that came out with a positive net present value, and as we spoke several times already, you know, there is a lot of additional customer programs and benefits that the AMI, as a foundation, enables that, again, we didn't have those costs and benefits in our cost-benefit model because they just weren't designed yet. We didn't know what the costs were in each of those cases, you know, will be on their own. So in general, with a positive business case, and plus the fact that we know there is additional customer products and services that this solution can enable, the Company has made a decision that this is a viable project that we want to move forward with.

MR. SOMERS: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: Questions by the Commission?

EXAMINATION BY COMMISSIONER GRAY:

Q. Mr. Schneider, in the revised cost-benefit analysis -- it was, I believe, submitted in December of 2017 -- do you have an estimate of the break-even year when the revised cost-benefit analysis -- what is the break-even year because of the changes in that cost-benefit analysis?

A. Yes. I don't recall exactly what that -- I was thinking -- and I may be getting this confused with the DEP case, but I was thinking it was 2025.

Q. In your direct testimony, on page 6, you describe AMI on line 6 and 7 that the meters have voltage and reactive power measurement capability.

Can you tell me what that is?

A. Yeah. So, without getting too technical from an engineering perspective, you have kilowatts and you have kVARs. So it's watts and VARs make up the total power. And so we can measure both VARs and watts with these meters.

Q. Is this going to be part of the expansion of AMI; this is part of the AMI?

A. This is part of the AMI, yes.

Q. All right. Some customers who hear about AMI have suggested that they want to be bypassed because they don't want to use the radio frequencies, they don't want to use -- what percentage of customers, so far in DEC, or perhaps even DEP too, have opted out?

A. So DEC, again, we don't have the ruling on the order, but what we are doing with customers that have concerns, of course, we try to address their concerns, but if they are still adamant about not wanting the meter, we put them on a bypass list. And currently, today, we have just a little over 4,000 on that list, which comes out to .3 percent. And I think, in our opt-out case -- like I said, I think this is general across all jurisdictions -- we use an estimated .1 percent, which is what we are seeing in all other jurisdictions. And so what happens is, if you don't have the opt-out tariff approved as you are deploying, and you just put people on bypass list, that grows up to that .3, even sometimes to .5. But then when you get the opt-out tariff, and they have to make that commitment to pay for that opt-out, that's when they accept the meter. So that's when it drops down to that .1 that we have seen across all jurisdictions. But we are at .3 percent right now on the bypass list for DEC North Carolina.

Q. When you install a net metering customer, someone who perhaps may have a solar panel on their roof, is the process and cost the same for other residential customers?

A. Yeah. It's the exact same meter.

Q. Exact same. Thank you. In your rebuttal, on page 13, lines 4 and 9, we talked about cost causation and appropriate pricing of goods and services to be produced by the Company must all be considered and strict cost-benefit analysis.

Do you mean that customers who benefit from a good or service should be the ones who pay for it?

A. Repeat the question?

Q. Rebuttal, page 13, lines 4 and 9.

A. (Witness peruses document.)

Okay.

Q. Are you with me?

A. Yes, I am.

Q. And it -- starting on 5, "The need to properly identify cost causation, and to appropriately price the goods and services provided by the Company must also be considered."

Are you with me?

A. Yes, I am.

Q. Does that mean that the customers who benefit from a good or service should be the ones who pay for it?

A. No. I don't necessarily agree with that.

Q. All right. And let me think.

COMMISSIONER GRAY: That's it for now. Thank you.

CHAIRMAN FINLEY: All right. Questions on the Commission's questions?

Commissioner Brown-Bland has questions.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Just a quick one, Mr. Schneider. With regard to -- do you know or have a good idea whether, with respect to the information that the customers receive in their home energy reports, that kind of information where it compares the usage with the neighborhood's usage, do you know from that what percentage of the DEC customers are in the top category, the lowest usage and most efficient?

A. No. I'm just vaguely familiar with that report.

Q. For the customers who get the little -- at least my report, I had the little house, and it will say, "Way to go" --

A. I get the same thing.

Q. -- "you are better than your neighbors" --

CHAIRMAN FINLEY: Or worse.

BY COMMISSIONER BROWN-BLAND:

Q. -- in your usage and efficiency."

For those customers, will they be able to get savings benefits, do you think, out of the AMI meters?

A. Again, I think they would, if they -- you know, if they take the initiative to go out and look at their usage information on a regular basis and understand their usage patterns and how they can change habits to reduce their energy usage. I will say that report you are referring to does not rely on AMI data.

Q. Right.

A. Yeah.

Q. But assuming those customers, one day in the future, will have AMI, I'm just wondering -- and given that they already have a low -- you know, high efficiency, low use, will they be able to benefit and to what extent?

A. I would say yes, by looking at their detailed usage information on a regular basis instead of wait until the end of the month and get the bill and realize how much energy you used.

Q. So I don't know if this is a recognized phenomenon, but kind of like the Prius effect, is there any information, either within the industry with other companies you know that have deployed AMI more fully than here in North Carolina, or on the basis of Company pilots or experimentations, is there any observance that, after some period of time, you know, the newness of the whole phenomenon of being able to get the information from AMI kind of wanes, and their interest in continuing to try to make use of that AMI information and reduce their usage, does that kind of drop off after a while?

A. Yeah. I don't know if I read any reports that speak to that, but I certainly could see where that would be possible. But I think, you know, if they truly are looking at it and trying to reduce their usage, they change their habits, and if they see their bills go down, they wouldn't have a need to continually look at their usage.

COMMISSIONER BROWN-BLAND: All right. Thank you.

CHAIRMAN FINLEY: Commissioner Patterson has questions.

EXAMINATION BY COMMISSIONER PATTERSON:

Q. Just one. Let's say I live in a mobile home, 2-inch thick walls, leaky windows, leaky doors, leaky roof; is AMI gonna help me?

A. Well, again, by being able to look at your energy usage, you know, you can see if it's a space heater you are using or something like that, and that you are running it all day, you would be able to see that, you know, hey, if I turn that off, or if I turn my thermostat down in the winter, that I can see the results of that conservation and reduction in my energy use.

Q. Assuming I'm still alive.

CHAIRMAN FINLEY: Mr. Schneider, I take it that the Company was not too pleased with the assumption the Commission had in its last order about AMI meters, right?

THE WITNESS: I don't know how to answer

that one.

CHAIRMAN FINLEY: That's all right. Questions on the Commission's questions?

MR. SOMERS: I have one.

FURTHER REDIRECT EXAMINATION BY MR. SOMERS:

Q. Mr. Schneider -- I realize I'm holding everybody up, so I will be quick -- both Commissioner Gray and Commissioner Patterson asked some very insightful questions about benefits and who should pay for this.

In the Company's opinion, do all customers benefit from AMI deployment, and if so, how?

A. Yes. All customers benefit, you know, that -- there are several of the things that I mentioned earlier that all customers receive benefits, from; the convenience and everything else. But probably the other areas would be the cost savings that are the benefits that are in our business case. So those reduced costs all customers see. And then if customers do reduce their energy usage, that would reduce the fuel cost that all customers would see as well.

MR. SOMERS: Thank you. No further questions.

CHAIRMAN FINLEY: All right. So, Mr. Schneider, thank you very much. We will receive the cross -- without objection, we will receive the cross examination exhibits of EDF, with the exception of Exhibit Number 2.

(Whereupon, EDF Schneider Cross Examination Exhibit Nos. 1, 3, 4, and 5 were admitted into evidence.)

CHAIRMAN FINLEY: All right. This brings us to the end of the case for this week. We will start up again on Monday at 9:30, but we will -- because of the conflict with the hearing we have in Little Washington Monday night, we will not go later than 3:00 on Monday, and because the panel has got to come back from Little Washington on Tuesday, we will not start before 10:30 on Tuesday, for planning purposes. Otherwise, 9:30 on Monday.

COMMISSIONER BROWN-BLAND: I'd just say, to recognize, I know at least Ms. Downey will be traveling that way with us.

CHAIRMAN FINLEY: Try not to get lost, okay. Come back at 9:30.

(The hearing was adjourned at 6:06 p.m. and set to reconvene at 9:30 a.m. on

Monday, March 19, 2018.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA )
COUNTY OF WAKE )

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 20th day of March, 2018.

JOANN BUNZE, RPR

Notary Public #200707300112

Panel of
Janice Hager, Michael J. Pirro, Lon Huber
Stipulated Exhibits from DEC Evidentiary Hearing

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

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# Electric Cost Allocation for a New Era

## A Manual

By Jim Lazar, Paul Chernick and William Marcus

Edited by Mark LeBel

JANUARY 2020

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That said, responsibility for the information and views set out in this work lies entirely with the authors.

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Jim Lazar, senior advisor with the Regulatory Assistance Project, is an economist who studied economics and energy at Western Washington University and the University of Washington. He has maintained a consulting practice in utility regulation and pricing and has made more than 100 appearances as an expert witness in rate proceedings in many different jurisdictions. His first utility rate proceeding was in 1974. As a RAP senior advisor, he has advised utility regulators across the United States and in Europe, India, Asia, Africa and South America. He is a former member of the U.S. Department of Energy Electricity Advisory Committee. Mr. Lazar has published more than 20 reference handbooks and topical papers on utility regulation and planning.

Paul Chernick, president of Resource Insight Inc., studied technology and policy at the Massachusetts Institute of Technology. He has advised clients on a wide range of issues, including restructuring policy; estimation of stranded costs; market price forecasts; market valuation of generation resources and divestiture of generation assets; planning and rate-making for central supply, energy efficiency, renewable and distributed resources, and least-cost compliance with environmental regulations; cost allocation and rate design; transmission and distribution planning; and valuation of environmental externalities. Mr. Chernick has testified in more than 300 regulatory and judicial proceedings. He began his career in 1977 with the Massachusetts attorney general's office.

William Marcus, principal of MCPM Economics — a successor company to JBS Energy Inc., where he worked for 32 years — studied economics at Harvard University and the University of Toronto. He began his energy career with the California Energy Commission in 1978. Mr. Marcus has more than 40 years of experience analyzing utility resource plans, costs and rates. He has prepared cost and rate studies for numerous clients and has testified as an expert witness in more than 40 jurisdictions.

Taken together, the three authors have more than 120 years of experience in cost allocation and rate design issues. They have been qualified and testified as expert witnesses before 43 state utility regulatory agencies, eight Canadian provinces and many other local, state and federal regulatory bodies.

# About the Editor

Mark LeBel, associate at the Regulatory Assistance Project, has more than a decade of experience working on the overlapping economics and law of energy and environmental policy in the United States. As a member of RAP's U.S. team, he focuses on rate design and regulatory reform, including compensation for distributed energy resources, the evolution of the electricity system and beneficial electrification.

# Figures

# Tables

# Introduction and Overview

The purpose of this manual is to provide a comprehensive reference on electric utility **cost allocation** for a wide range of practitioners, including utilities, intervenors, utility regulators and other policymakers. Cost allocation is one of the major steps in the traditional regulatory process for setting utility rates. In this step, the regulators are primarily determining how to equitably divide a set amount of costs, typically referred to as the **revenue requirement**, among several broadly defined classes of ratepayers. The predominant impact of different cost allocation techniques is which group of customers pays for which costs. In many cases, this is the share of costs paid by residential customers, commercial customers and industrial customers.

In addition, the data and analytical methods used to inform cost allocation are often relevant to the final step of the traditional regulatory process, known as **rate design**. In this final step, the types of charges for each class of ratepayers are determined — which can include a per-month charge; charges per **kilowatt-hour** (kWh), which can vary by season and time of day; and different charges based on measurements of **kilowatt** (kW) **demand** — as well as the price for each type of charge. As a result, cost allocation decisions and analytical techniques can have additional efficiency implications.

Cost allocation has been addressed in several important books and manuals on utility regulation over the past 60 years, but much has changed since the last comprehensive publication on the topic — the 1992 *Electric Utility Cost Allocation Manual* from the **National Association of Regulatory Utility Commissioners** (NARUC). Although these works and historic best practices are foundational, the legacy methods of cost allocation from the 20th century are no more suited to the new realities of the 21st century than the engineering of internal combustion engines is to the design of new electric motors. New electric vehicles (EVs) may look similar on the outside, but the design under the hood is completely different. This handbook both describes the current best practices that have been developed over the past several decades and points toward needed innovations. The authors of this manual believe strongly that charting a new path forward on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

Charting a new path on cost allocation is an important part of creating the fair, efficient and clean electric system of the future.

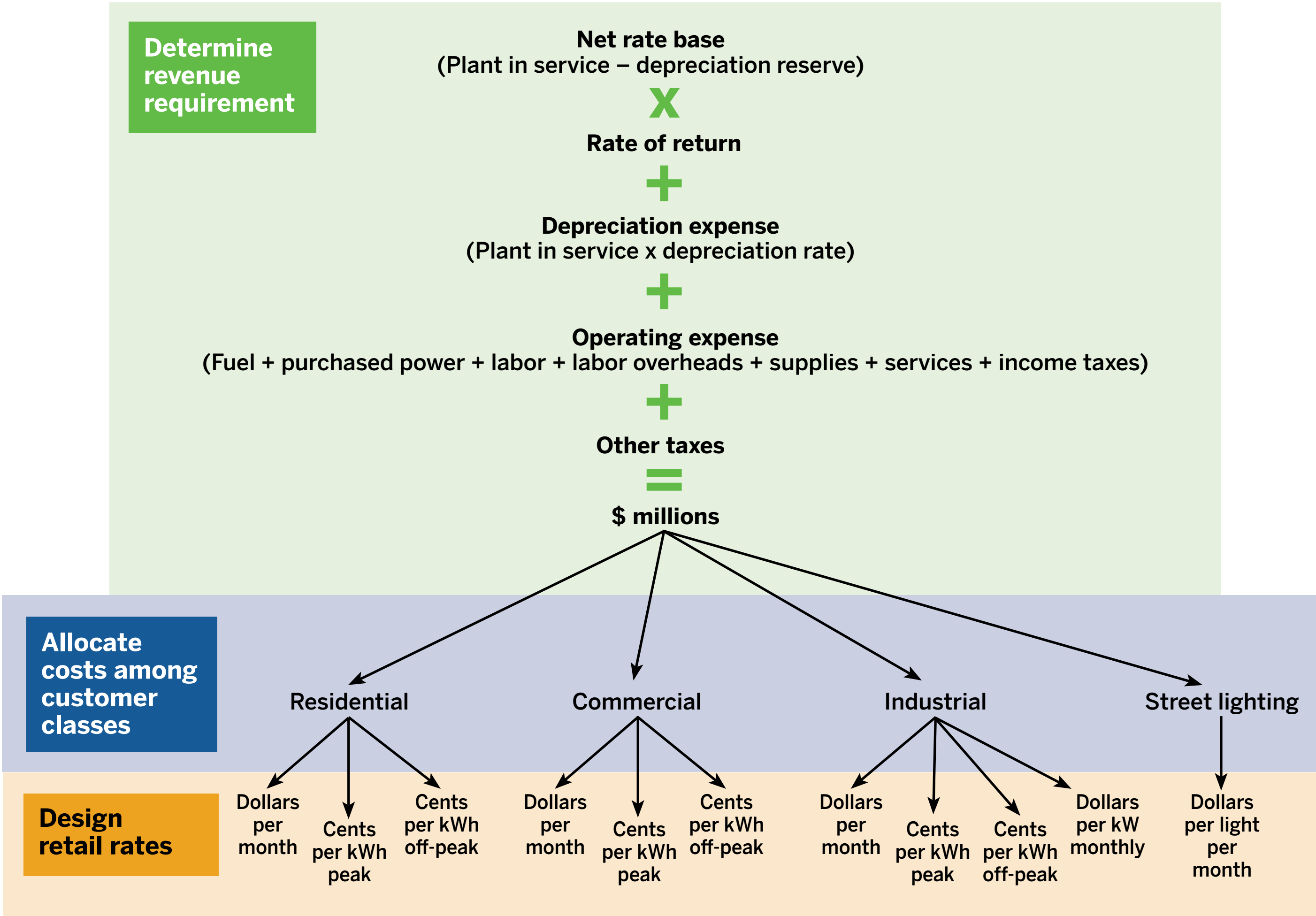
## Scope and Context of This Manual

This manual focuses on cost allocation practices for electric utilities in the United States and their implications. Our goal is to serve as both a practical and theoretical guide to the analytical techniques involved in the equitable distribution of electricity costs. This includes background on regulatory processes, purposes of regulation, the development of the electricity system in the United States, current best practices for cost allocation and the direction that cost allocation processes should move. Most of the elements of this manual will be applicable elsewhere in the Americas, as well as in Europe, Asia and other regions.

The rate-making process for **investor-owned utilities** (IOUs) has three steps: (1) determining the annual revenue requirement, (2) allocating the costs of the revenue requirement among the defined rate classes and (3) designing the rates each customer ultimately will pay. Figure 1 on the next page presents a highly simplified version of these steps.

In the cost allocation step, there are two major quantitative frameworks used around the United States: **embedded cost of service studies** and **marginal cost of service studies**. Embedded cost studies typically are based on a single year-long period, using the embedded cost revenue requirement and customer usage patterns in that year to divide up costs.

Figure 1. Simplified rate-making process




Marginal cost of service studies, in contrast, look at how costs are changing over time in response to changes in customer usage.

Regardless of which framework will be used, an enormous amount of data is typically collected first, starting with the costs that make up the revenue requirement, **energy** usage by **customer class** and measurements of demand at various times and often extending to data on **generation** patterns. Furthermore, when the quantitative **cost of service study** is completed, regulators typically don't take the results as the final word, often making adjustments for a wide range of policy considerations after the fact.

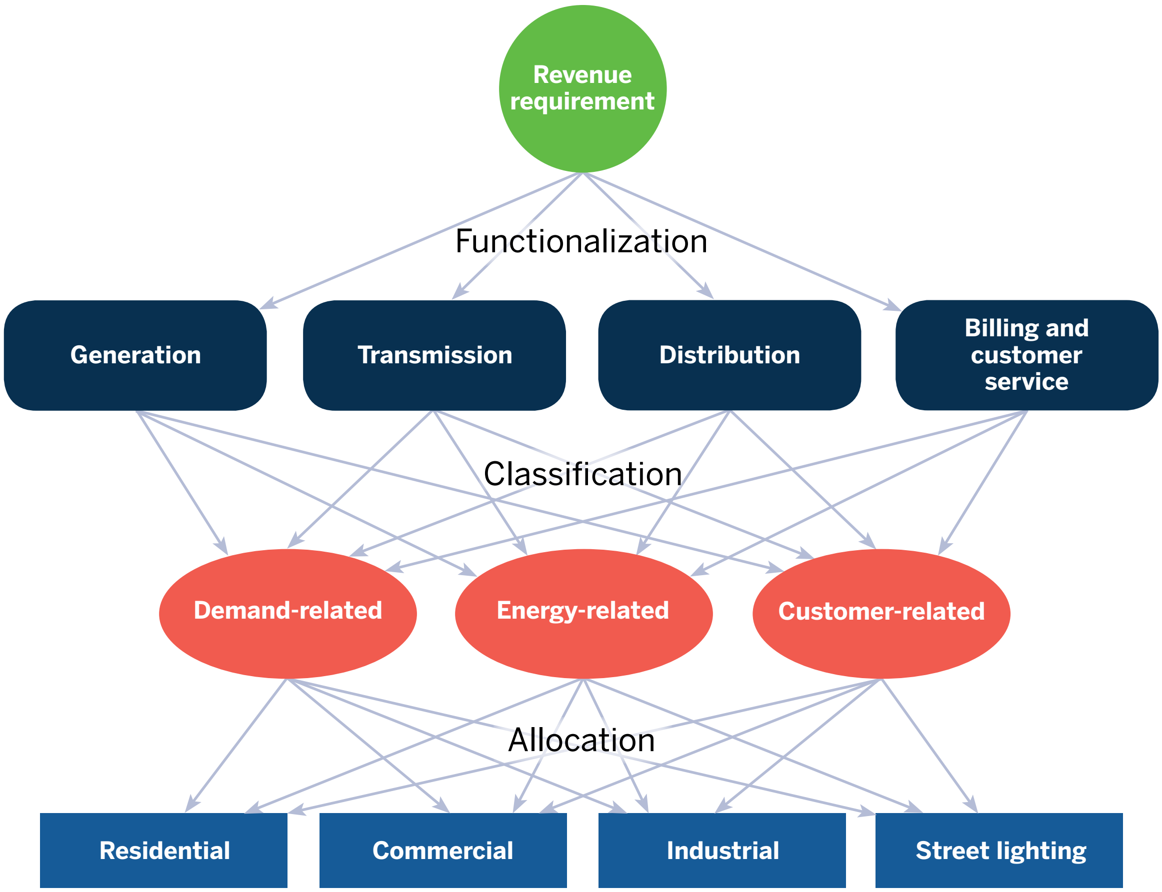
Traditionally, the analysis for an embedded cost of service study is itself divided into three parts: **functionalization**, **classification** and **allocation**. Figure 2 on the next page shows the traditional flowchart for this process.

The analysis for a marginal cost of service study starts with a similar functionalization step, but that is followed by estimation of marginal unit costs for each element of the system, calculation of a **marginal cost revenue requirement** (MCRR) for each class as well as for the system as a whole, and then **reconciliation** with the annual embedded cost revenue requirement.

This cost allocation manual is intended to build upon previous works on the topic and to illuminate several areas where the authors of this manual disagree with the approaches of the previous publications. Important works include:

- *Principles of Public Utility Rates* by James C. Bonbright (first edition, 1961; second edition, 1988).
- *Public Utility Economics* by Paul J. Garfield and Wallace F. Lovejoy (1964).

**Figure 2. Traditional embedded cost of service study flowchart**




- *The Economics of Regulation: Principles and Institutions* by Alfred E. Kahn (first edition Volume 1, 1970, and Volume 2, 1971; second edition, 1988).
- *The Regulation of Public Utilities* by Charles F. Phillips (1984).
- The 1992 NARUC *Electric Utility Cost Allocation Manual.*

Of course, cost allocation has been touched upon in other works, including RAP's publication *Electricity Regulation in the United States: A Guide* by Jim Lazar (second edition, 2016). However, since the 1990s, there has been neither a comprehensive treatment of cost allocation nor one that addresses the emerging issues of the 21st century. This manual incorporates the elements of these previous works that remain relevant, while adding new cost centers, new operating regimes and new technologies that today's cost analysts must address.

## Continuing Evolution of the Electric System

Since the establishment of electric utility regulation in the United States in the early 20th century, the electric system has undergone periods of great change every several decades. Initial provision of electricity service in densely populated areas was followed by widespread rural electrification in the 1930s and 1940s. In the 1950s and 1960s, **vertically integrated utilities**, owning generation, **transmission** and **distribution** simultaneously, were the overwhelmingly dominant form of electricity service across the entire country.

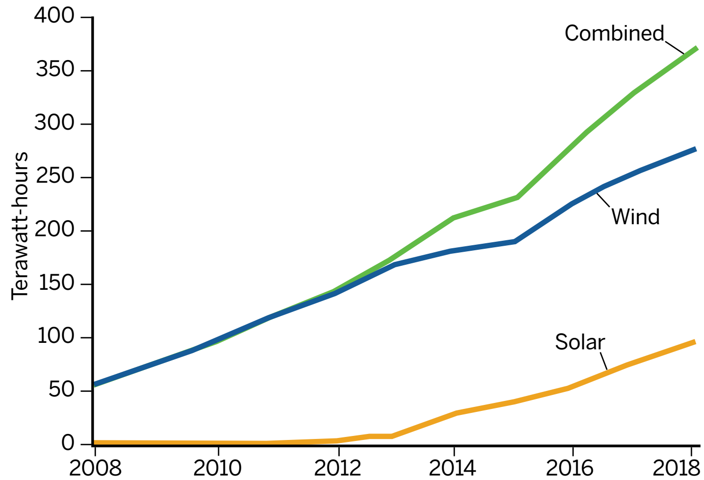
However, the oil crisis in the 1970s sparked a chain reaction in the electric industry. That included a new focus by utilities on **baseload generation** plants, typically using coal or nuclear power. At the same time, the federal government began to open up competition in the electric system with the passage of the **Public Utilities Regulatory Policy Act** (PURPA) of 1978. PURPA dictated that each state utility commission consider a series of standards to reform rate-making practices, including **cost of service**.[1] Nearly every state adopted the recommendation that rates should be based on the cost of service, but neither PURPA nor state regulators were clear about what that should mean. This has led to a fertile legal and policy discussion about the cost of service, how to calculate it and how to use it. PURPA also required that utilities pay for power from **independent power producers** on set terms.

In the 1970s and early 1980s, major increases in oil prices, the completion of expensive capital investments in coal and nuclear generation facilities and general inflation all led to significantly higher electricity prices across the board. These higher prices, in combination with PURPA's requirement for set compensation to independent power producers, led to demands by major consumers to become wholesale purchasers of electricity. This in turn led to the Energy Policy Act of 1992, which enabled the broader restructuring of the electric industry in much of the country around the turn of the 20th century.

The key texts and most of the analytical principles currently used for cost allocation were developed between the 1960s and early 1990s. Since that time, the electric system in the United States has been undergoing another period of dramatic change. That includes a wide range of interrelated advancements in technology, policy and economics:

- Major advances in data collection and analytical capabilities.
- Restructuring of the industry in many parts of the country, including new wholesale electricity markets, new retail markets and new market participants.
- New consumer interests and technologies that can be deployed **behind the meter**, including clean **distributed generation**, **energy efficiency**, **demand response**, storage and other energy management technologies.
- Dramatic shifts in the relative cost of technologies and fuels, including massive declines in the price of **variable renewable resources** like wind and solar and sharp declines in the cost of energy storage technologies.
- The potential for beneficial electrification of end uses that currently run directly on fossil fuels — for example, electric vehicles in place of vehicles with internal combustion engines.

**Figure 3. Increase in US wind and solar generation from 2008 to 2018**




Data source: U.S. Energy Information Administration. (2019, February). *Electric Power Monthly.* Table 1.1.A. Retrieved from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01_a

Many, if not all, of these changes have quantifiable elements that can and should be incorporated directly into the regulatory process, including cost allocation. The increased development of renewable energy and the proliferation of more sophisticated meters provide two examples.

Figure 3 illustrates the dramatic increase in wind and solar generation in the United States in the last decade, based on data from the U.S. Energy Information Administration.

Traditional cost allocation techniques classify all utility costs as **energy-related**, **demand-related** or **customer-related**. These categories were always simplifications, but they must be reevaluated given new developments. Some legacy cost allocation methods would have treated wind and solar generation entirely as a demand-related cost simply because they are capital investments without any variable **fuel costs**. However, wind and solar generation does not necessarily provide firm **capacity** at peak times as envisioned by the legacy frameworks, and it displaces the need for fuel supply, so it doesn't fit as a demand-related cost.

1 The PURPA rate-making standards are set forth in 16 U.S.C. § 2621. Congress in 2005 adopted a specific requirement that cost of service studies take time of usage into account; this is set forth in 16 U.S.C. § 2625.

**Table 1. Types of meters and percentage of customers with each in 2017**

| | Residential | Commercial | Industrial |
|---|---|---|---|
| **Advanced metering infrastructure** | 52.2% | 50.0% | 44.5% |
| **Automated meter reading** | 29.5% | 26.5% | 28.0% |
| **Older systems** | 18.3% | 23.5% | 27.5% |

Data source: U.S. Energy Information Administration. *Annual Electric Power Industry Report, Form EIA-861: 2017* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861/

In addition, many utilities now collect much more granular data than was possible in the past, due to the widespread installation of **advanced metering infrastructure** (AMI) in many parts of the country and other advancements in the monitoring of the electric system. As a result, utility analysts often have access to historical hourly usage data for the entire utility system, each distribution **circuit**, each customer class and, increasingly, each customer. Some **automated meter reading** (AMR) systems also allow the collection of hourly data, typically read once per billing cycle. Table 1 shows the recent distribution of meter types across the country, based on data from the U.S. Energy Information Administration. Improved data collection allows for a wide range of new cost allocation techniques.

In addition, meters have been primarily treated as a customer-related cost in older methods because their main purpose was customer billing. However, advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and **line loss** reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs.

These are just two examples of how recent technological advances affect appropriate cost allocation. In subsequent chapters, this manual will address each major cost area for electric utilities, the changes that have occurred in how costs are incurred and how assets are used, and the best methods for cost allocation.

## Principles and Best Practices

There is general agreement that the overarching goal of cost allocation is equitable division of costs among customers. Unfortunately, that is where the agreement ends and the arguments begin. Two primary conceptual principles help guide the way to the right answers:

1. Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?

In some cases these two frameworks point to the same answer, but in other cases they conflict. The authors of this manual believe that "costs follow benefits" is usually, but not always, the superior principle. Other helpful questions can be asked to illuminate the details of particularly difficult questions, such as:

- If certain resources were not available, which services would not be provided, and what different resources would be needed to provide those services at least cost?
- If we did not serve this need in this way, how would costs change?

In the end, cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

In that spirit, we would like to highlight the following current best practices discussed at more length in the later chapters of this manual. To begin, there are best practices that apply to both embedded and marginal cost of service studies:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the **basic customer method**.
- Apportion all shared generation, transmission and distribution assets and the associated operating expenses

on measures of usage, both energy- and demand-based.

- Ensure broad sharing of overhead investments and **administrative and general (A&G) costs**, based on usage metrics.
- Eliminate any distinction between **"fixed" costs** and "variable" costs, as capital investments (including new technology and data acquisition) are increasingly substitutes for fuel and other short-run variable operating costs.
- Where future costs are expected to vary significantly from current costs, make the cost trajectory an important consideration in the apportionment of costs.

Second, there are current best practices specific to embedded cost of service studies:

- Classify and allocate generation capacity costs using a time-differentiated method, such as the **probability-of-dispatch** or **base-intermediate-peak** (BIP) methods, or classify capacity costs between energy and demand using the **equivalent peaker method**.
- Allocate demand-related costs for generation using a broad peak measure, such as the **highest 100 hours** or the **loss-of-energy expectation**.
- Classify and allocate the costs of transmission based on its purpose, with any demand-related costs allocated based on broad peak periods for regional networks and narrower ones for local networks.
- Classify distribution costs using the basic customer method, and divide the vast majority of costs between demand-related and energy-related using an energy-weighted method, such as the **average-and-peak method** that many natural gas utilities use.
- Allocate demand-related distribution costs using appropriately broad peak measures that capture the hours with high usage for the relevant system elements while appropriately accounting for **diversity** in customer usage.
- Ensure that customer connection and service costs appropriately reflect differences between customer classes by using either specific cost studies for each element or a weighted customer approach.
- Functionalize and classify AMI and billing systems according to their multiple benefits across different elements and aspects of the electric system.

Lastly, there are current best practices for marginal cost of service studies:

- Use **long-run marginal costs** for generation that reflect lower greenhouse gas emissions than the present system, and recognize the costs of emissions that do occur as **marginal costs** during those periods.
- Analyze whether demand response, storage or market capacity purchases are cheaper than a traditional peaking **combustion turbine** as the foundation of marginal generation capacity cost.
- Use an expansive definition of marginal costs for transmission and distribution, including automation, controls and other investments in avoiding capacity or increasing reliability, and consider including replacement costs over the relevant timeframe.
- Recognize marginal line losses in each period.
- Functionalize marginal costs in **revenue reconciliation**; use the **equal percentage of marginal cost** technique by function, not in total.

## Path Forward and Need for Reform

Our power system is changing, and cost allocation methods must also change to reflect what we are experiencing. Key changes in the power system that have consequences for how we allocate costs include:

- Renewable resources are replacing fossil generation, substituting invested capital in place of variable fuel costs.
- **Peaking resources** are increasingly located near **load** centers, eliminating the need for transmission line investment to meet **peak demand**. Long transmission lines are often needed to bring baseload coal and nuclear resources, and to bring wind and other renewable resources, even if they may have limited peaking value relative to their total value to the power system.
- Storage is a new form of peaking resource — one that can be located almost anywhere and has low variable costs. Storage can help avoid generation, transmission and distribution **capacity-related costs**. The total costs of storage need to be assigned to the proper time period for equitable treatment of customer classes.

- Consumer-sited resources, including solar and storage, are becoming essential components of the modern **grid**. The **distribution system** may also begin to serve as a gathering system for power flowing from locations of local generation to other parts of the utility service territory, the opposite of the historical top-down electric delivery model.
- **Smart grid** systems make it possible to provide better service at lower cost by including targeted energy efficiency and demand response measures to meet loads at targeted times and places and other measures to take advantage of improved data and operational capabilities.

Unfortunately, older techniques, even those resulting from detailed inquiries by cutting-edge regulators in recent decades, may not be sufficiently sophisticated to incorporate new technologies, more granular data and advancements in analytical capabilities. As a result, innovations are needed in the regulatory process to mirror the changes taking place outside of **public utilities commissions**.

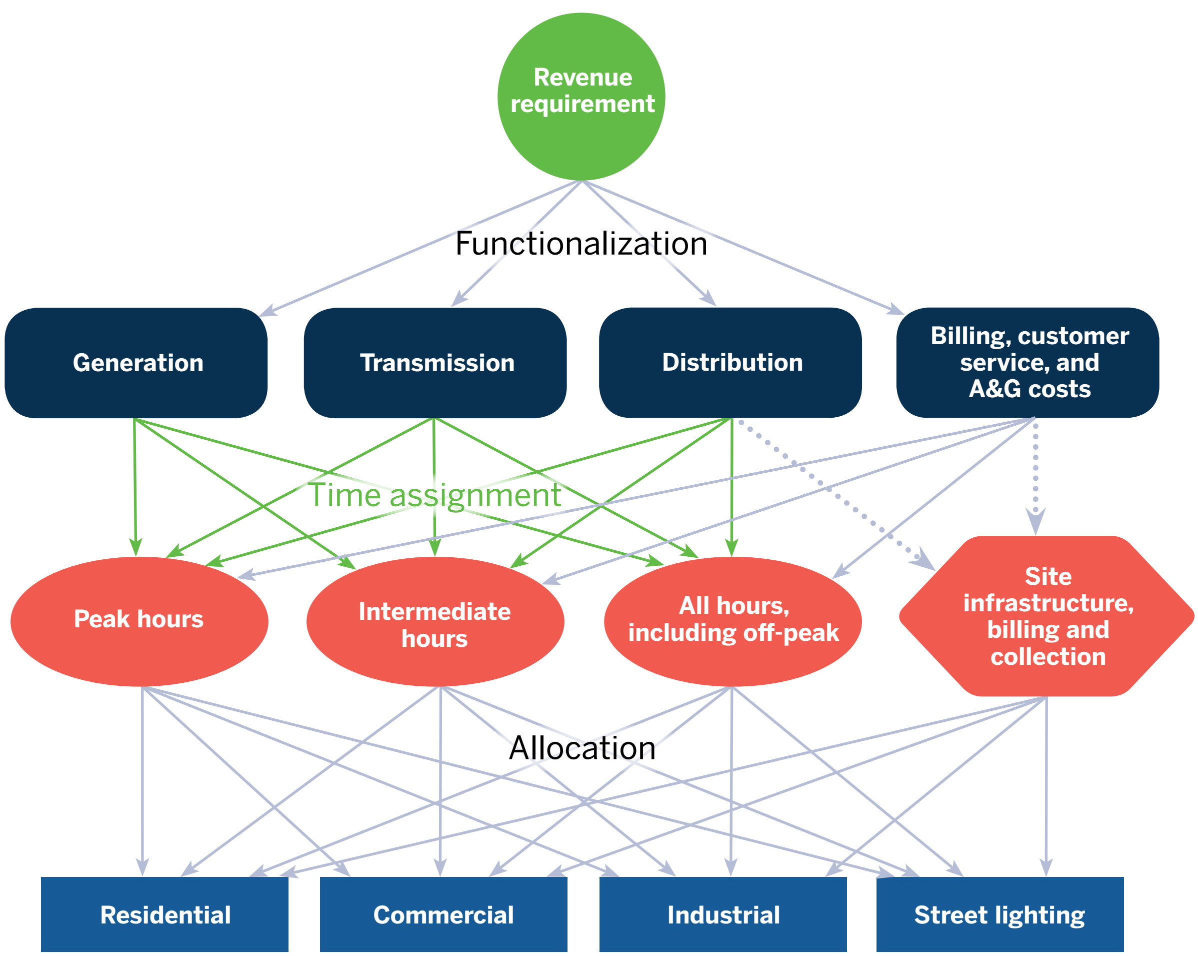
For all cost of service studies, these innovations could include:

- Clear distinction between shared assets and customer-specific assets in the accounting for distribution costs.
- Clearer tracking of distinctions between system costs and overhead investments and expenses at all stages of the rate-making process.
- More accurate definitions of rate classes based on emerging economic and service characteristic distinctions between customers.
- Distinction between loads that can be controlled to draw power primarily at low-cost periods and those that are inflexible.

For embedded cost of service studies, innovative **hourly allocation** techniques could incorporate a number of advances, including:

- Hourly methods for generation: Most generation costs

**Figure 4. Modern embedded cost of service study flowchart**



should be assigned to the hours in which the relevant facilities are actually used and to all hours across the year, not solely based on measurements in a subset of these hours.

- Hourly methods for transmission: Transmission costs must be examined to determine the purpose and usage patterns, and costs must be assigned to the hours when the transmission services are utilized to serve customer needs.
- All shared distribution costs should be apportioned based on the time periods when customers utilize these facilities. The system is needed to provide service in every hour, and in most cases a significant portion of the distribution system cost should be assigned volumetrically to all hours across the year.
- Billing, customer service and A&G costs that do not vary based on consumption should be functionalized separately.
- **Site infrastructure** to connect customers, billing and collection should be a separate classification category.

Figure 4 shows an example of a modern time-based allocation method in a reformed flowchart.

Innovation in marginal cost of service studies could take the form of more granular hourly marginal cost analysis for the generation, transmission and shared distribution elements of the system. Alternatively, a more conceptual shift to the **total service long-run incremental cost** method developed for the restructuring of the telecommunications industry should be considered. This method estimates the cost of building a new optimally sized system using current technologies and costs. This avoids a number of significant issues with traditional marginal cost of service studies, particularly the problem of significant swings in estimates based on the presence or absence of excess capacity, but it comes with additional data requirements and new uncertainties.

These proposed innovations, regardless of whether they are adopted widely, shed new light into the foundations of cost allocation and may help the reader gain insight into the underlying questions. More generally, we hope that readers find this manual useful as they undertake the complex task of apportioning utility costs among functions, customer classes and types of service and that they join us in finding the best path forward.

## Guide to This Manual

After this introduction and summary, this manual is divided into five parts:

- Part I: Chapters 1 through 4 lay out principles of economic regulation of electric utilities, background on the rate-making process, and definitions and descriptions of the electric system in the United States. Readers who are new to rate-making and utility regulation should start here for the basics.[2] Much of this material likely will be familiar to an experienced practitioner but emphasizes key issues relevant to the remainder of the manual.
- Part II: Chapters 5 through 8 cover the important definitions, basic techniques and overarching issues in cost allocation. Some of this material may be familiar to an experienced practitioner but also lays out the issues facing cost allocation.
- Part III: Chapters 9 through 17 delve deeply into the subject of embedded cost of service studies, including discussion of historic techniques, current best practices and key reforms.
- Part IV: Chapters 18 through 26 cover the field of marginal cost of service studies, including historical development, current best practices and key needed reforms.
- Part V: Chapters 27 and 28 cover what happens after the completion of the quantitative studies, including presentation of study results and adjustments, and the relationship between cost allocation and rate design.

The conclusion wraps up with final thoughts.

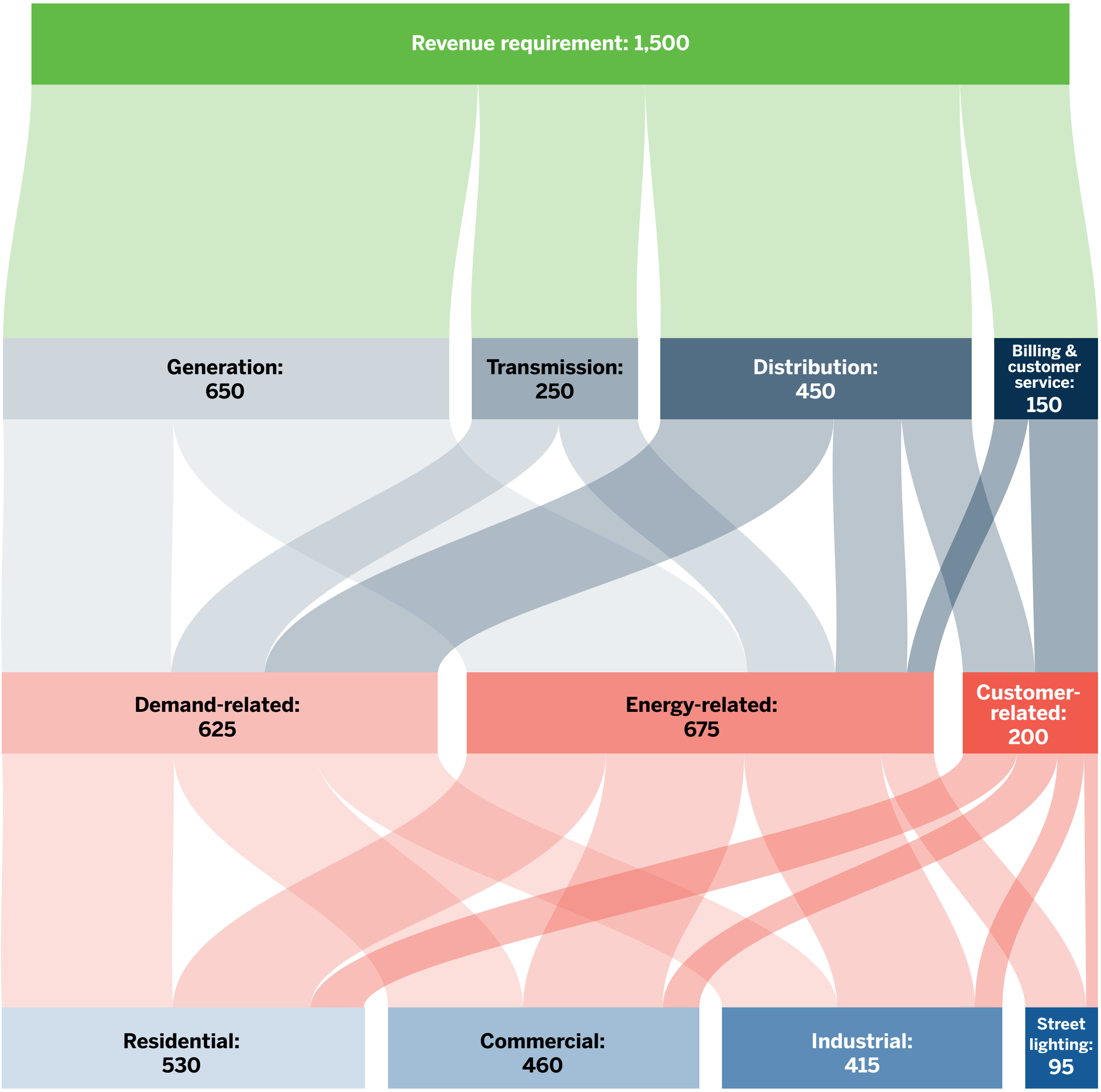
Each part of this manual ends with a list of works cited. Terms defined in the glossary are set off in boldface type where they first appear in the text.

2 For a more detailed handbook on the structure and operation of the industry, see Lazar, J. (2016). *Electricity Regulation in the United States: A Guide* (2nd ed.). Montpelier, VT: Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/

## Visual display of cost allocation results

Like much of utility regulation, visual display of information in cost allocation tends to be dry and difficult to understand. Much of the analytical information for cost allocation tends to be displayed in large tables that only experts can interpret. Simple flowcharts, such as Figure 2 on Page 16, are also quite common and convey little substantive information. Nevertheless, it should be possible to convey cost allocation results in a meaningful way that a wider audience can understand. One possibility is to convert the traditional flowcharts into Sankey diagrams, where the width of the flows is proportional to the magnitude of the costs. Figure 5 shows this type of diagram for a traditional embedded cost of service study.

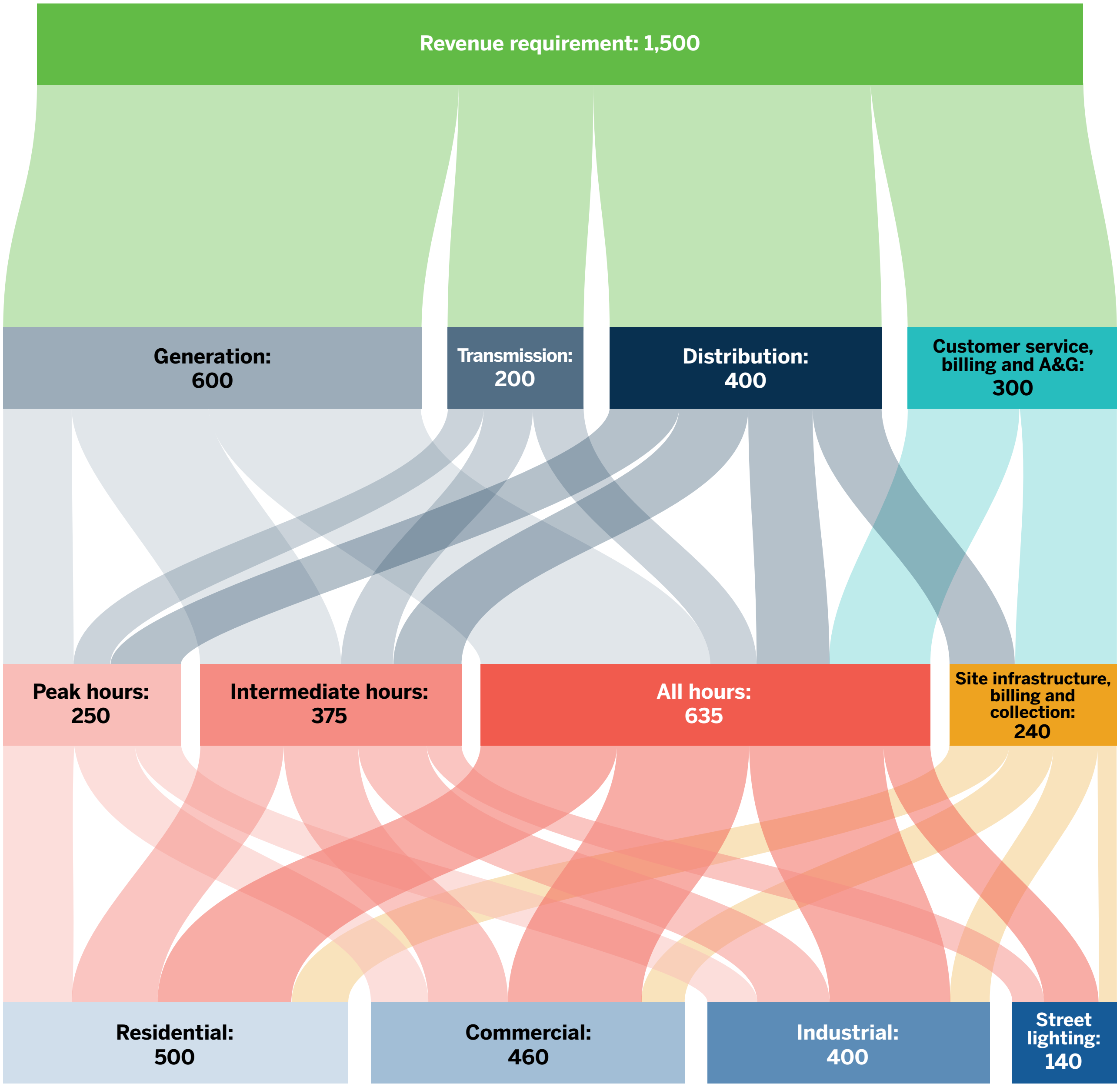
**Figure 5. Sankey diagram for traditional embedded cost of service study**



A Sankey diagram can display a tremendous amount of information in a way that is reasonably understandable. At the top, it begins with the overall revenue requirement, then splits into three functions. Next, each function splits into the different classifications, which are then allocated by customer class. At each step, the overall costs stay constant, but the relative sizes for each function, classification and customer class are readily apparent. Additionally, the colors in the diagram can be used to indicate additional distinctions. Figure 6 is a Sankey diagram for a more complex reformed embedded cost of service study. Like Figure 5, it shows illustrative results that are feasible with certain allocation techniques. In contrast, the flowcharts in figures 2 and 4 show all the different allocation possibilities with arrows linking different categories.

As the Sankey diagram becomes more complex, it can be less intuitive. Yet it is likely a much more understandable visual representation of the key elements of a cost of service study.

**Figure 6. Sankey diagram for modern embedded cost of service study**



# Part I:

# Economic Regulation and the Electric System in the United States

# 1. Economic Regulation in the U.S.

Economic regulation of privately owned business dates back to the Roman Empire and was a significant feature of government in medieval England, where accommodation prices at inns were regulated because travelers typically had only a single choice when arriving at the end of a day on foot or horseback. In the later medieval period, the English Parliament regulated bakers, brewers, ferrymen, millers, smiths and other artisans and professionals (Phillips, 1984, p. 77). This tradition was brought to the United States in the 19th century, when a series of Supreme Court opinions held that grain elevators, warehouses and canals were monopoly providers of service "affected with a public interest" and that their rates and terms of service could therefore be regulated.[3]

> Property does become clothed with a public interest when used in a manner to make it of public consequence, and affect the community at large. When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good …
> — U.S. Supreme Court, Munn v. Illinois, 94 U.S. 113, 126 (1877)

## 1.1 Purposes of Economic Regulation

The primary purpose of economic regulation has always been to prevent the exercise of monopoly power in the pricing of essential public services. Whether applying to a single inn along a stagecoach route or an electric utility serving millions of people, the essence of regulation is to impose on monopolies the pricing discipline that competition imposes on competitive industries and to ensure that consumers pay only a fair, just and reasonable amount for the services they receive and the commodities they consume. Historically, electric utility service is considered a "natural monopoly" where the cost of providing service is minimized by having a single system serving all users. In recent years, competition has been introduced into the power supply function in some areas. The delivery service remains a natural monopoly in all areas, however, and in much of the U.S., power supply is provided at retail by only a single monopoly utility.

Over time, legislative and regulatory bodies have identified subsidiary purposes of regulation, but these all remain subordinate to this primary purpose of preventing the abuse of monopoly power. These subsidiary purposes include:

- Defining and assuring the adequacy of service for customers, including reliability and access to electric service at reasonable prices.
- Setting prices so that the utility has a reasonable opportunity to receive revenue sufficient to cover prudently incurred costs, provide reliable service and allow the utility to access capital.
- Avoiding unnecessary and uneconomic expenditures or protecting customers from the costs of imprudent actions.
- Encouraging or mandating practices deemed important for societal purposes, such as reducing environmental damage and advancing technology.
- Managing intentional shifts in cost responsibility from one customer group to another, such as economic development discounts for industrial customers or assistance for low-income and vulnerable customers.

When monopoly power ceases to be a concern, as when there are many buyers and sellers in a transparent market, the basis for imposing price regulation evaporates. Transportation and telecommunications services used to be regulated in the United States, but as technology changed in a way that

3 Munn v. Illinois, 94 U.S. 113 (1877). The term "affected with a public interest" originated in England around 1670, in two treatises by Sir Matthew Hale, Lord Chief Justice of the King's Bench, De Portibus Maris and De Jure Maris. Munn v. Illinois, at 126-128.

allowed competition, policymakers eliminated the economic regulation, or at least changed the essential features of the regulatory structure. A similar phenomenon has occurred with the introduction of wholesale markets for electricity generation in many parts of the country.

## 1.2 Basic Features of Economic Regulation

To prevent the exercise of monopoly power, the primary regulatory tool used by governments has been control over the prices the regulated company charges. During the decline of the Roman Empire, emperors issued price edicts for more than 800 articles based on the cost of production (Phillips, 1984, p. 75). Utility regulators today review proposals for rates from utilities and issue orders to determine a just and reasonable rate, typically based on the cost of service. However, price regulation raises the question of the quality and features of the product or service. Inevitably, this means that price regulation must logically extend to other features of the product or service. In the case of electricity, this means utility regulators typically have regulatory authority over the terms of service and often set standards for reliability to ensure a high-quality product for ratepayers.

In the regulation of prices for utility service, the prevailing practice, known as **postage stamp pricing**, is to develop separate sets of prices for a relatively small and easily identifiable number of classes of customers. For electric utilities, one typical class of customers is residential.

> We are asking much of regulation when we ask that it follow the guide of competition. As Americans, we have set up a system that indicates we have little faith in economic planning by the government. Yet, we are asking our regulators to exercise the judgment of thousands of consumers in the evaluation of our efficiency, service and technical progress so that a fair profit can be determined. Fair regulation is now, and always will be, a difficult process. But it is not impossible.
>
> — Ralph M. Besse, American Bar Association annual meeting, August 25, 1953 (Phillips, 1984, p. 151)

James Bonbright, regarded as the dean of utility rate analysts, set out eight principles that are routinely cited today.

For a given utility and its service territory, all customers in this class pay the exact same prices. Postage stamp pricing clearly deviates from strict cost-based pricing but addresses a number of regulatory needs. It keeps the process relatively simple by limiting the number of outputs that need to be produced to one set of rates for each broad customer class. Since rates need to be tied to the cost of service, this logically implies that the cost of service must be determined separately for each rate class, which is one of the key outputs of the cost allocation phase of a **rate case**.

Postage stamp pricing also puts an end to one of the unfair pricing strategies monopolies undertake, known as price discrimination. Price discrimination — that is, strategically charging some customers more than others — helps a monopolist maximize profits but also serves as a way for an unregulated monopolist to punish some customers and reward others. Of course, different pricing can be appropriate for customers that incur different costs.

## 1.3 Important Treatises on Utility Regulation and Cost Allocation

This handbook recognizes the pathbreaking work done by cost and rate analysts in the past. It is important to review these foundational works, recognize the wisdom that is still current and identify how circumstances have changed to where some of their theories, methodologies and recommendations are no longer current with the industry.

James Bonbright is regarded as the dean of utility rate analysts. His book *Principles of Public Utility Rates*, first published in 1961, addresses all of the elements of the regulatory process as it then stood, with detailed attention to cost allocation and rate design. Bonbright set out eight principles that are routinely cited today (1961, p. 291):

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. …
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Of these, principles 6 and 7 are the most closely related to cost allocation.

Bonbright's chapters on marginal costs (Chapter 17) and fully distributed costs (Chapter 18) are most relevant to this manual's purpose. His analysis of marginal costs carefully distinguishes between **short-run marginal costs** (in which capital assets are not changeable) and long-run marginal costs (in which all costs are variable) and discusses which are most applicable for both cost allocation and rate design. A second edition of this book, edited by Albert Danielsen and David Kamerschen, was published posthumously in 1988.

Paul Garfield and Wallace Lovejoy published their book *Public Utility Economics* in 1964. This text focuses on the economic structure of the industry and the need to have costs and rates measured in terms that elicit rational response by consumers. This text also provides an excellent set of principles for cost allocation and rate design with respect to the shared capacity elements of costs:[4]

1. All service should bear a portion of capacity costs.
2. Capacity charges attributed to each user should reflect the amount of time used, peak characteristics, interruptible characteristics and diversity.
3. Customers with continuous demand should get a bigger share of capacity costs than those with intermittent demand, because the intermittent demand customers have diversity and can share capacity.
4. No class gets a free ride. Every class, including fully **interruptible customers**, must contribute something to the overall system costs in addition to the variable costs directly attributable to its usage.

Alfred Kahn first published *The Economics of Regulation* in two volumes in 1970 and 1971, and a second edition was issued in 1988. Kahn raised the innovative notion of using marginal costs, rather than **embedded costs**, as a foundation of rate-making generally and cost allocation and rate design more specifically. Some states use this approach today. Kahn also served as a regulator, as the chair of both the New York Public Service Commission and the federal Civil Aeronautics Board, which oversaw the deregulation of airlines.

Charles Phillips published *The Regulation of Public Utilities* in 1984, and subsequent editions were released in 1988 and 1993. Phillips wrote in the post-PURPA era, at a time when utility construction of major baseload generating units was winding down. He addressed the desirability of recognizing the difference between baseload and peaking investments as well as the evolution of these cost differentiations into **time-varying rates**. Up to that time, few attempts had been made to prepare time-varying embedded cost studies.

The National Association of Regulatory Utility Commissioners published its *Electric Utility Cost Allocation Manual* in 1992. That handbook provided explicit guidance on some of the different methods that regulators used at that time to apportion rates for both embedded cost and marginal cost frameworks. It was controversial from the outset, due to omission of a very common method of apportioning distribution costs — the basic customer method. However, it is the most recent, comprehensive and directly relevant work on cost allocation prior to this manual.

4 Simplified from principles attributed to Henry Herz, consulting economist, cited in Garfield and Lovejoy (1964, pp. 163-164).

# 2. Main Elements of Rate-Making

The process of setting rates varies significantly among states and different types of utilities, such as investor-owned utilities regulated by state utility commissions and self-regulated **municipal** and **cooperative utilities**. However, the most basic and essential elements are typically the same. The discussion in this chapter focuses on the methods used for IOUs, with occasional notes on distinctions in other contexts.

There are three distinct elements, or phases, in a rate case, and each phase feeds into the next. The first determines the required level of annual revenue, typically known as the revenue requirement. The second phase, the primary subject of this manual, apportions the revenue requirement among a small number of customer classes, traditionally with additional distinctions made between customer-related costs, demand-related costs and energy-related costs. Finally, the individual prices, formally known as **tariffs** or rates,[5] are designed in order to collect the assigned level of revenue from each class. These elements can be considered by the regulator at the same time or broken into separate proceedings or time schedules. Regardless, the analysis is inevitably sequential. This chapter ends with a brief description of the key features of the procedure used in rate cases.

## 2.1 Determining the Revenue Requirement

The revenue requirement phase of a conventional rate case consists of determining the allowed **rate base**, allowed **rate of return** and allowed operating expenses for the regulated utility on an annualized basis. In most jurisdictions, the annualized revenue requirement is developed for a "**test year**," which is defined as either a recent year with actual data, which may be adjusted for known changes, or projections for a future year, often the period immediately after the expected conclusion of the rate case. A few elements of the revenue requirement phase have important bearing on the cost allocation study, and we address only these.[6]

Many regulated utilities in the modern United States are one corporation within a broader holding company, which may include other regulated utilities or other types of corporate entities. Early in the revenue requirement process, the utility must identify the subset of costs relevant to the regulated operations that are the subject of a rate case and separate those costs from other operations and entities. This is generally called a jurisdictional allocation study. It is likely that a holding company that has both regulated and unregulated activities has some activities that are of a fundamentally different nature and level of risk from the operations of the regulated utility in question, where sales and revenues can be relatively stable. Jurisdictional allocation is generally beyond the scope of this manual, but many of the principles for apportioning costs among classes may also be relevant for apportioning those costs among multiple states served by a single utility or utility holding company.

Within the subset of costs identified by the regulated utility, the regulator has the discretion to disallow certain costs as imprudent or change key parameters used by the utility to determine the overall revenue requirement. Disallowance of major costs, such as investments in power plants that were not completed or did not perform as expected, have occurred and have led to the bankruptcy of a utility in at least one case.[7] Smaller disallowances or adjustments are more common, such as a reduction in the allowed rate of return the utility proposes, as well as common disallowances for advertising and executive or incentive compensation, which would lower the revenue requirement commensurately.

5 This is an important difference between British English, where "rates" refers to property taxes, and American English, where the term means retail prices.

6 For a more detailed discussion of the determination of the revenue requirement, see Chapter 8 of Lazar (2016).

7 This was the Public Service Company of New Hampshire and the Seabrook nuclear plant (Daniels, 1988).

**Performance-based regulation** (PBR) may divert from the strict cost accounting approach of the conventional rate case, relying on the performance of the utility to meet goals set by the regulator as a determinant of all or a portion of the revenue requirement.[8]

At the end of this phase, the regulated utility has been assigned a certain level of revenue that it is expected to be able to collect in the **rate year** following the end of the rate case. This annualized revenue requirement is passed along to the next step in the process.

## 2.2 Cost Allocation

In the second phase of a rate case, the overall revenue requirement is divided up among categories of utility customers, known as classes. These customer classes are usually quite broad and can contain significant variation but are intended to capture cost differentials among different types of customers. Some utilities have many customer classes, but typical classes for each utility include residential customers, small business customers, large commercial and industrial (C&I) customers, irrigation and pumping, and street lighting customers.

At this stage in the process, the utility will use different types of data it has collected to assign costs to each customer class. The types of data available have changed over time, but historically these have included energy usage in specific time periods, different measures of demand, the number of customers in each class and information on generation patterns. In addition, utility costs are categorized using a tracking system known as the Uniform System of Accounts. This system was established by the Federal Power Commission — now the **Federal Energy Regulatory Commission** (FERC) — around 1960, leading to the shorthand of "FERC accounts." Further detail is provided in Appendix A.

These data will be used in a cost of service study that attempts to equitably divide up the revenue requirement among the rate classes. There are two major categories in these studies: an embedded cost of service study (or fully allocated cost of service study), which focuses on the costs the utility intends to recover and other metrics for one year; and a marginal cost of service study, which estimates the responsibility of customer classes for system costs in the future.

An embedded cost of service study itself typically has three major steps:

1. Functionalization of costs as relevant to generation, transmission, distribution and other categories, such as billing and customer service and administrative and general costs.
2. Classification of costs as customer-related, demand-related or energy-related.
3. Allocation among rate classes.

An embedded cost of service study directly splits up the revenue requirement, which is itself calculated on an embedded cost basis.

A marginal cost of service study has a different structure. It begins with a similar functionalization of costs, separately analyzing generation, transmission and distribution. The next step is the estimation of marginal unit costs for different elements of the electric system and customer billing. The estimated marginal costs are then multiplied by the billing determinants for each class. This produces a class marginal cost revenue requirement; when combined with other classes, it's a system MCRR. However, revenue determination solely on this marginal cost basis typically will be greater or less than the allowed revenue requirement, which is normally computed on an embedded cost basis. It is only happenstance if the MCRR is the same as, or even similar to, the revenue requirement calculated on an embedded cost basis. As a consequence, the results of a marginal cost of service study must be reconciled to recover the annual revenue requirement.

Although both embedded and marginal cost studies include precise calculations, most regulators are not strictly bound by the results. Numerous other factors are involved in cost allocation for each rate case, including gradualism of rate changes, policy considerations, such as anticipated changes, and economic conditions in the service territory. The data developed for cost allocation and the analytical techniques used in the cost of service studies can provide helpful information for other purposes, such as rate design. Careful attention

8 For an example of a framework that divorces utility earnings from utility investment, see Lazar (2014). For a broader discussion of performance-based regulation, see Littell et al. (2017).

must be paid, however, to the reason the data were developed, and caution must be taken so that this information is used constructively in an appropriate manner.

The final allocation of costs among the rate classes, as well as the other relevant data and analysis, is passed on to the next step in the process.

## 2.3 Rate Design

The rate design phase of a proceeding is sometimes separated in time from the previous phases so the parties know the revenue amounts that each class is expected to contribute, or it may be combined into a single proceeding with the other two phases. This manual does not address rate design principles in detail, but they are addressed in two companion publications by RAP: *Smart Rate Design for a Smart Future* (Lazar and Gonzalez, 2015) and *Smart Non-Residential Rate Design* (Linvill, Lazar, Dupuy, Shipley and Brutkoski, 2017). Related issues around compensation for customers with distributed generation are also addressed in RAP's *Designing Distributed Generation Tariffs Well* (Linvill, Shenot and Lazar, 2013).

At the highest level, the principles used for rate design are significantly different from those for cost allocation. Rate design should always focus on forward-looking efficiency, including concepts like long-run marginal costs for the energy system and societal impacts more generally, because rate design will influence consumer behavior, which in turn will influence future costs.

Rate design decisions also include principles around understandability and the ability of customers to manage their bills and respond to the price signals in rates. Of course, equity is also a consideration in the rate design process, but in a significantly different context: Primarily, it's concerned with the distribution of costs among individual customers within a rate class.

There are three basic rate components:

1. **Customer charges**: fees charged every billing period that generally do not vary with respect to any usage characteristics.
2. **Volumetric energy charges**: prices based on metrics of kWh usage during the billing period.
3. **Demand charges**: prices based on metrics of kW or **kilovolt-ampere** (kVA) power draw during the billing period.

These three basic options allow for a wide range of variations based on season, time of day and type of demand measurement. All types of rates can vary from season to season or month to month, often based on either the cost of service study or energy market conditions.[9] Both demand charges and **energy charges** measure the same thing: electricity consumption over a period of time. Even though demand charges are typically denominated in kWs as a measurement of power draw, virtually all demand charges are actually imposed on consumption within short windows, often the highest 15-, 30- or 60-minute window during the billing period.[10] Because it is based on the maximum within those short windows, a demand charge effectively acts as a one-way ratchet within a billing period. Additional ratchets can be imposed over the course of the year, where the demand charge may be based on the greater of either billing period demand or 90% of the maximum demand within the previous year. In contrast, energy charges are based on consumption throughout a billing period, with no ratchets. Energy charges can vary by time within a billing period, generically known as time-varying rates.[11] Common variants include **time-of-use** (TOU) energy charges, where prices are set separately for a few predetermined time windows within each billing period; and **critical peak pricing**, where significantly higher prices are offered for a short time period announced a day or two in advance in order to maximize customer response to events that stress the system.

Some rate analysts propose rates that rigorously follow the results of a cost allocation study, meaning that customer-related costs must be recovered through customer charges and demand-related costs must be recovered through

9 Rates that vary by season are often referred to as seasonal rates. However, some utilities also define "seasonal" customer classes for customers who have a disproportionate share of their usage during a particular time period. Rates for seasonal customer classes may also be referred to as seasonal rates, which can cause confusion.

10 Note that in these cases kWs is a simplified description of kWhs per hour since it is not truly an instantaneous measurement.

11 Some analysts may describe certain types of demand charges as time-varying rates as well, such as those that are imposed only within certain time windows (e.g., 2 to 6 p.m. on nonholiday weekdays).

demand charges. However, most analysts do not and are careful to note that categorizations like "demand-related" are simplifications at best and, as this manual details, generally reflect an increasingly obsolete framework. Forward-looking efficiency is not a feature of embedded cost of service studies and additionally may require consideration of broader **externalities** that are not necessarily incorporated in the revenue requirement. Similarly, rate design must consider customer bill impacts and the related principles of understandability, acceptability and customer bill management.

## 2.4 Rate Case Procedure

Although procedures at state utility commissions vary greatly, there are typically several common elements. Most rate cases begin with a proposal from the regulated utility. In the most formal terms, a utility commission is adjudicating the rights, privileges and responsibilities of the regulated utility, although typically without the full formalities and rules of a judicial proceeding. Other interested parties are allowed to become intervenors to participate in discovery, present witnesses, brief the issues for the commission and potentially litigate the result in court. This process often automatically includes an official state consumer advocate. A wide range of stakeholders may join the process, including large industrial consumers, chambers of commerce, low-income advocates, labor, utility investors, energy industries and environmental advocates. These non-utility parties can critique the utility proposal and can propose alternatives to utility cost allocation methods as well as other substantive elements of the rate case. Rate cases can be resolved through a final decision by the utility commission based on the record presented, or some or all aspects of a rate case can be resolved through a settlement among the various parties.

The costs of a rate case for the regulated utility are considered part of the cost of service and ultimately become part of the revenue requirement determined in the rate case. Many states make explicit funding arrangements for the commission itself and any state consumer advocate, often ultimately recovered from ratepayers. In some states and most Canadian provinces, ratepayer funding was historically given to other intervenors who participated productively in the process, a practice that continues in California. However, it is much more common for stakeholders to bear the burden of any litigation costs, which limits the ability of many stakeholders to advance their interests at this level.

# 3. Basic Components of the Electric System

The electric utility system, for general descriptive purposes and for regulatory and legal purposes, typically is divided into several categories of activities and costs, including generation, transmission, distribution, billing and customer service, and A&G costs. In a vertically integrated utility, a single entity owns and operates all of these, although many other forms of market structure and ownership exist in the United States. Each of these segments includes capital investments and labor and nonlabor operating expenses. Each of these segments is operated and regulated according to different needs and principles.

These distinctions at each level of the power system are important to cost allocation, and the terminology is important to understand. Many of the arguments about proper allocation of costs hinge on the purpose for, and capabilities of, capital investments and the nature of operating expenses. Thus, having a correct understanding of the purpose, limitations and current usage of each major element of the system is important to resolve key cost allocation questions. Figure 7 is a diagram of a traditional electric power system, with one-way power flow from a large central generation facility through the transmission and distribution system to end-use customers (U.S.-Canada Power System Outage Task Force, 2004).

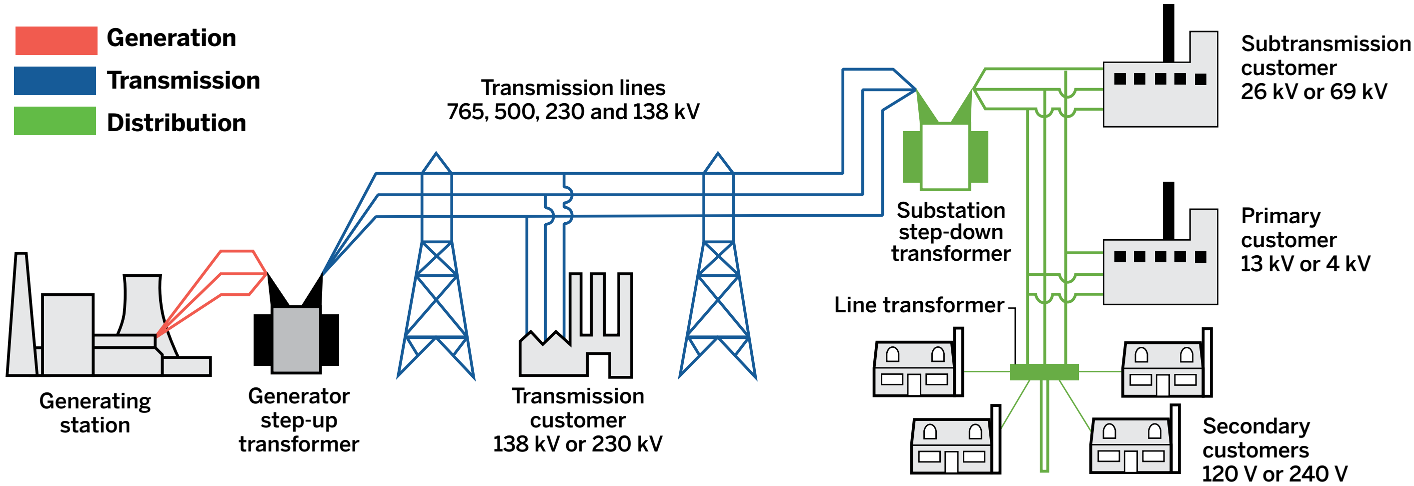
The evolving electric grid will be much different from the grid of the past hundred years. The "smart grid" of the future will look different, operate differently and have different cost centers and potentially different sources of revenues. As a result, it will need different cost allocation methods. Figure 8 on the next page shows a vision of the direction the electric system is evolving, with generation and storage at consumer sites, two-directional power flows, and more sophisticated control equipment for customers and the grid itself (U.S. Department of Energy, 2015).

This manual discusses many of the changes underway in the electric system, but undoubtedly the future will bring further change and new challenges.

## 3.1 Categories of Costs

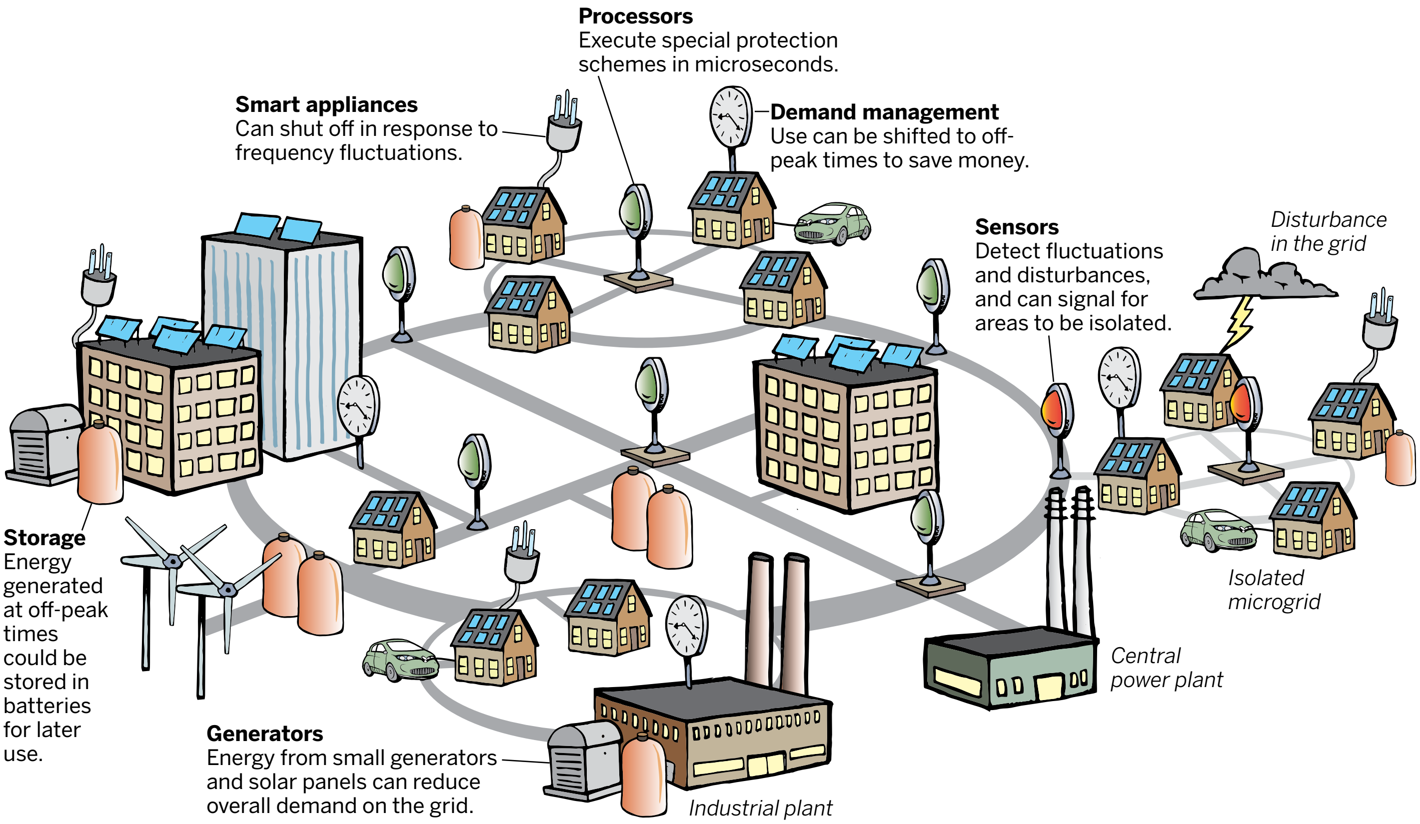
All decisions that a utility makes have consequences for its overall cost of service. Some of those decisions were made decades ago, as the utility made investments — including large power plants and office buildings — based on conditions

**Figure 7. Illustrative traditional electric system**




Source: Adapted from U.S.-Canada Power System Outage Task Force. (2004). *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*

**Figure 8. Illustrative modern electric system**




Source: Adapted from U.S. Department of Energy. (2015). *United States Electricity Industry Primer*

or forecasts at that time. Some of the decisions are made every day, as the utility dispatches power plants or replaces worn-out distribution equipment. Many of the decisions that determine the utility's revenue requirement — such as the historical decisions to build particular power plants in particular locations — result from complex processes involving past expectations and many practical complications and trade-offs.

### 3.1.1 Generation

Electricity generation[12] comes from many different types of technologies that utilize many different types of fuels and resources. Most types of steam-electric units burn fuel, which can be oil, coal, natural gas, biomass or waste products, in a boiler to produce steam to turn a turbine. This turbine then turns an electric generator. Most steam units are older and generally limited in their ability to cycle on and off. This means they can only change generation levels slowly and may require many hours to start up, shut down and restart.

Some noncombustion technologies use a steam turbine to generate electricity. Some geothermal units use steam to drive a turbine, using heat transferred up from underground to boil water. Concentrated solar power, or solar thermal, uses heat from the sun to boil water and spin a turbine. Nuclear generation also uses a steam turbine, where the heat to boil water comes from a chain reaction of uranium fission.

Combustion turbines, which are similar to jet engines, use heated gases from the combustion of either a liquid or gaseous fuel to directly spin a turbine and generate electricity. Simple cycle combustion turbines directly exhaust a significant amount of heat. Combustion turbines can be turned on and off very quickly and require high-quality, relatively clean fuels because of the contact between the combustion gas and the turbine blades.

12 Some sources, including the FERC accounts and the 1992 NARUC *Electric Utility Cost Allocation Manual*, use the term "production" instead of "generation." This manual uses the term "generation" and generally includes exports from storage facilities under this category.

**Combined cycle units** include combustion turbines but capture the waste heat to boil water, produce steam and spin an extra turbine to generate electricity. As a result, combined cycle units have higher capital costs than combustion turbines but generate more electricity for each unit of fuel burned.

Hydroelectric plants use moving water, either released from reservoirs or running in rivers, to spin turbines and generate electricity. These units vary widely in their seasonal generation patterns, storage capacity and dispatchability. Many, but not all, hydroelectric plants are easily dispatchable to follow load but may be constrained by minimum and maximum allowed river flows below the facility.

There are also a variety of noncombustion renewable resources, including wind power, solar photovoltaic (PV), solar thermal and potentially tidal and current power. In addition, fuel cells can generate electricity from hydrogen by using a chemical reaction. The only byproduct of a fuel cell reaction is water, but different methods of producing hydrogen can have different costs and environmental impacts.

Power supply can come from different types of energy storage facilities as well, although most of these resources also consume electricity. Traditional types of storage, such as pumped hydroelectric storage (where water is moved to higher ground using electricity at times of low prices and released back down to spin turbines at times of high prices) and flywheels have been around for many decades, but battery storage and other new technologies are becoming more prevalent. Different types of storage technologies can have very different capabilities, varying from a few minutes' worth of potentially exportable energy to a few months' worth, which determines the types of system needs that the storage can address. As a result, the allocation of these costs requires careful attention by the cost analyst.

Each of these technologies has a different cost structure, which can depend on the type of fuel used. This is typically divided among: (1) upfront investment costs, also known as capital costs; (2) **operations and maintenance (O&M) costs**, which may depend on the numbers of hours a facility generates ("dispatch O&M costs") or can be incurred regularly on a monthly or annual basis ("nondispatch O&M costs"); and (3) fuel costs. Fuel costs per unit of energy generation depend on the price of the fuel consumed and the efficiency of the unit; this is often defined as an efficiency percentage comparing input fuel potential energy to output electric energy, or as a **heat rate** defined as the **British thermal units** (Btu) of fuel input for every kWh of output electric energy.

Dirtier fuels, such as coal and oil, require expensive and capital-intensive pollution control equipment. Different costs are also incurred in the delivery and handling of each fuel prior to its use, as well as the disposal of any byproducts. For example, both coal ash and nuclear waste require disposal, and there are different controversies and costs associated with each. Noncombustion renewable resources have very low variable costs and relatively high capital costs. Storage resources generally have high investment costs, moderate maintenance costs and low operating costs. The decision around their dispatch is defined by the opportunity cost of choosing the hours to store and discharge, with the goal of picking the hours with the greatest economic benefit.

Some plants, mainly steam, combustion turbine and combined cycle, can be set up to use more than one fuel, primarily either natural gas or oil. Such a dual fuel setup involves a range of costs but allows the plant operator to choose the fuel that is less expensive or respond to other constraints.

Generation facilities are frequently categorized by their intended purpose and other characteristics. This terminology is evolving and does not necessarily reflect a permanent condition. For example, several types of units traditionally have been characterized as baseload because they are intended to run nearly all the time. This includes most steam-electric combustion units, particularly those run on coal. This also includes nuclear units, which run nearly all of the time with the exception of long refueling periods every few years that can last for months. Historically, **baseload units** had higher capital costs, which could be offset by lower fuel costs given their ability to run constantly. However, as fuel price patterns have changed, this is not always the case, particularly when natural gas is cheaper than coal.

Several types of plants are characterized as **peakers** or peaking units because they are flexible and dispatched easily at times of peak demand. Combustion turbines are the prime example of a peaking unit. Historically, these units had lower capital costs per unit of capacity and higher fuel costs per kWh generated. Again, this may no longer be true as fuel prices have changed.

Plants that are neither baseload nor peaking units are often referred to as **intermediate units**. They run a substantial portion of the year but not the whole year or just peak hours. "Midmerit" and "cycling" are commonly used synonyms for these types of generators. Over the last two decades, natural gas combined cycle facilities often filled this role in many parts of the country, but changing fuel costs and environmental regulations have altered the typical operating roles of many types of generation.

Hydroelectric units may effectively be baseload resources or may be storage reservoirs that allow generation to be concentrated in high-value hours. Other noncombustion renewable resources are often characterized as variable or **intermittent resources** because these technologies can generate electricity only in the right conditions — when the sun is shining, the wind is blowing or the currents are moving. However, the addition of storage to these facilities can make these characteristics much less relevant. In addition, the accuracy of forecasts for these resources has improved greatly. These variable renewable resources can also be operated in certain ways to respond to electric system or market conditions, such as through **curtailment**.

### 3.1.2 Transmission

**Transmission systems** comprise high-voltage lines, over 100 **kilovolts** (kV), that are generally carried via large towers (although sometimes on poles or buried underground) and the **substations** that interconnect the transmission lines both to one another and between generation resources and customers. Subtransmission lines that interconnect distribution substations, operating between 50 kV and 100 kV, may be functionalized as distribution plant.

Utilities use a variety of transmission voltages. A higher voltage allows more power to be delivered through the same size wires without excessive **losses**, overheating of the **conductor** (wire) or excessive drop in the operating voltage over the length of the line. Higher voltages require taller towers to separate the power lines from the ground and other objects and better insulation on underground cables but are usually less expensive than running multiple conductors at lower voltages where large amounts of power need to be delivered.

Transmission systems can also be either **alternating current** (AC) or **direct current** (DC). Some transmission using DC has been built because it can operate at high voltages over longer distances with lower losses; these lines are known as **high-voltage direct current** (HVDC). However, the vast bulk of the transmission system in the United States is AC.

Transmission serves many overlapping functions, including:

- Connecting inherently remote generation (large hydro, nuclear, mine-mouth coal, wind farms, imports) to load centers.
- Allowing power from a wide range of generators to reach any distribution substation to permit least-cost economic dispatch to reduce fuel costs.
- Providing access to neighboring utilities for **reserve** sharing, economic purchases and economic sales.
- Allowing generation in one area to provide backup in other areas.
- Reducing **energy losses** between generation sources and the distribution system, where transmission capacity is above the minimum required for service.

Each of these purposes carries different implications for cost allocation. Some transmission is needed in all hours, while other transmission is built primarily to meet peak requirements.

Transmission substations connect the generators to the transmission system and the various transmission voltages to one another. They also house equipment for switching and controlling transmission lines. Most substations are centered on large **transformers** to convert power from one voltage to another. The largest customers, such as oil refineries, often have their own substation and take delivery from the grid at transmission voltage.

### 3.1.3 Distribution

Distribution substations and lines are required for the vast majority of customers who take service at the distribution level. The distribution system receives power primarily from the transmission system through distribution substations, which convert power from higher transmission-level voltages down to distribution-level voltages. Some power may be delivered to the distribution system directly from small generators, such as small hydro plants and distributed generation. Distribution substations are smaller versions of transmission substations.[13] These are often connected by subtransmission lines, which may be functionalized as either transmission or distribution in cost studies. Collectively, the transmission and distribution systems are referred to as T&D or as the delivery system.

From each substation, one or more distribution feeders operating between 2 kV and 34 kV, known as **primary voltage** lines, run as far as a few miles, typically along roadways. These are mostly on wooden utility poles shared with telephone and cable services or in underground conduit. A single pole or underground route may carry multiple circuits. Each feeder may branch off to serve customers on side streets. Although distribution feeders leaving the substations are usually three-phase, like the transmission lines, branches that do not carry much load may be built as single-phase lines with just two wires.

Some customers take power directly at primary voltage (usually 2 kV to 34 kV) and transform it down within their premises to a **secondary voltage** (600 **volts** or less) or use it directly in high-voltage equipment. All residential and most commercial customers take service at secondary voltages, which typically range from 120 V to 480 V. For that purpose, the utility must provide **line transformers**, which are the large cylinders on some utility poles for overhead distribution and the ground-mounted metal boxes near buildings for underground distribution. There is a frequently used shorthand in which customers served at primary voltage are referred to as primary customers and any customer classes distinguished on this basis are described as primary — for example, primary **general service** or primary commercial. Similarly, customers served at secondary voltage can be described as secondary customers, and customer classes distinguished on that basis are referred to as secondary — for example, secondary general service or secondary commercial.

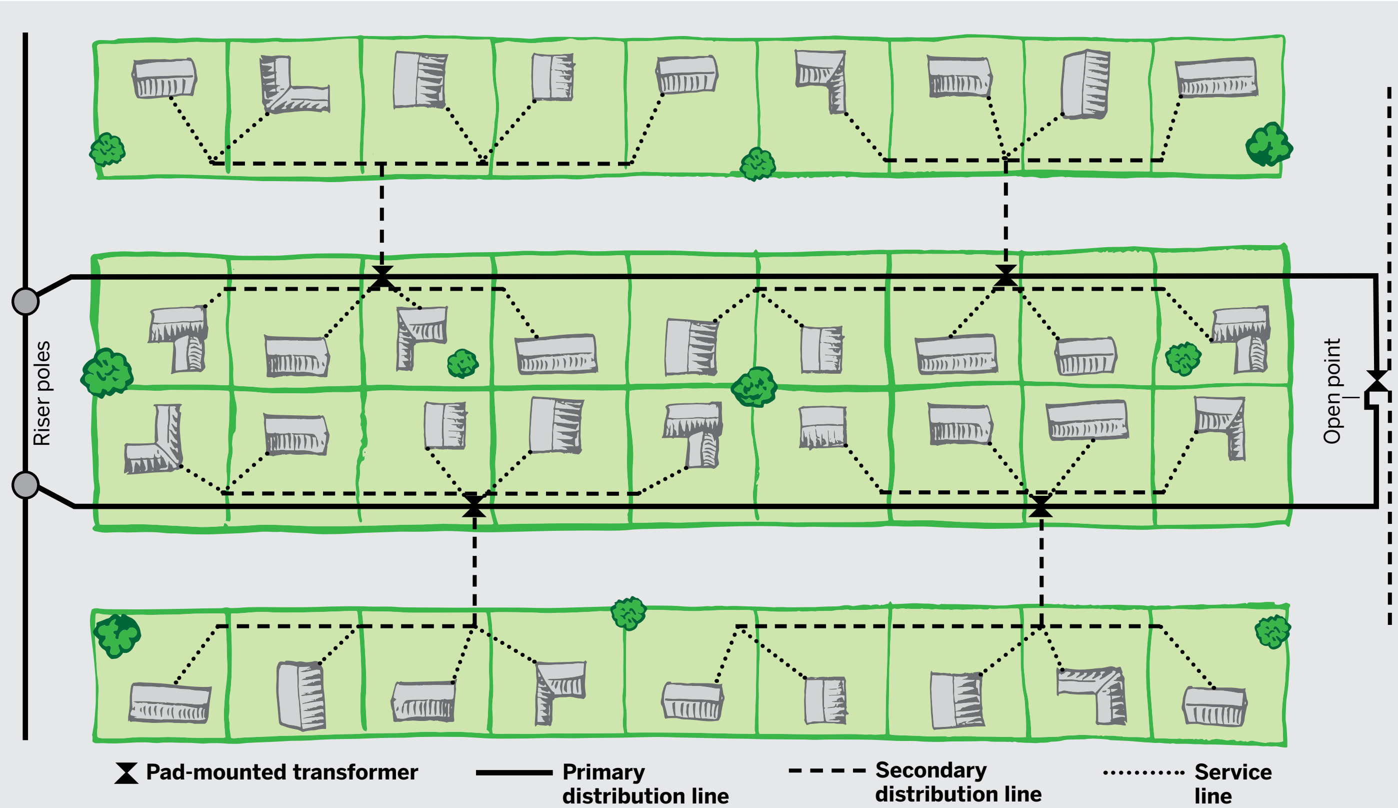
In urban and suburban settings, a typical transformer will serve several residential customers or small businesses, either in one building or several buildings that are relatively close to one another. Typically, an apartment building is served by a larger transformer than would serve single-family dwellings, but the transformer or multitransformer installation could serve dozens or even hundreds of customers. A single large secondary customer is usually served by one or more dedicated transformers, and in exurban and rural areas even a relatively small customer may be so far away from neighbors as to require a dedicated transformer.

Some secondary voltage customers will be served directly by a **service line** from the transformer to their buildings. Other customers farther up the road will be fed from a secondary distribution line from a nearby transformer that is attached to the same poles as the primary feeder but lower down. Secondary voltage lines in older neighborhoods served with overhead wires are often networked among several transformers. For many utilities, underground secondary lines in modern neighborhoods generally are not networked. Underground service is generally more expensive than overhead service but often required by local regulations for aesthetics or reliability reasons.

Figure 9 on the next page illustrates one relatively common arrangement. In this example, each transformer serves two houses directly with service lines, and feeds secondary lines from which service lines run to two or three other houses on the same side of the street and four or five houses across the street. The illustration is for an underground system. The basic layout of an overhead system would be similar. However, since it is easier to string overhead service lines across the street than to dig lines under the street, service lines might run directly from an overhead transformer to one or two houses across the street, and the secondary might just run on the transformers' side of the street, with service lines crossing the street to additional customers. The key factor here for cost allocation purposes is that even secondary voltage lines are often shared among multiple customers and are not a direct cost responsibility of any one of them individually.

13 In some cases, a higher-voltage distribution line (e.g., 13 kV) may power a lower-voltage line (e.g., 4 kV) through a substation.

**Figure 9. Underground distribution circuit with radial secondary lines**




Note: Overhead primary lines run down the riser poles and go underground.

Figure 10 shows a portion of a similar distribution circuit but highlights the difference that in this case the secondary lines are networked, meaning power can flow to the relevant customers over both transformers simultaneously. This allows each transformer to serve as backup for the others in that network and allows for more flexible operation to minimize losses and prevent overloads.

**Figure 10. Detail of underground distribution circuit with networked secondary lines**

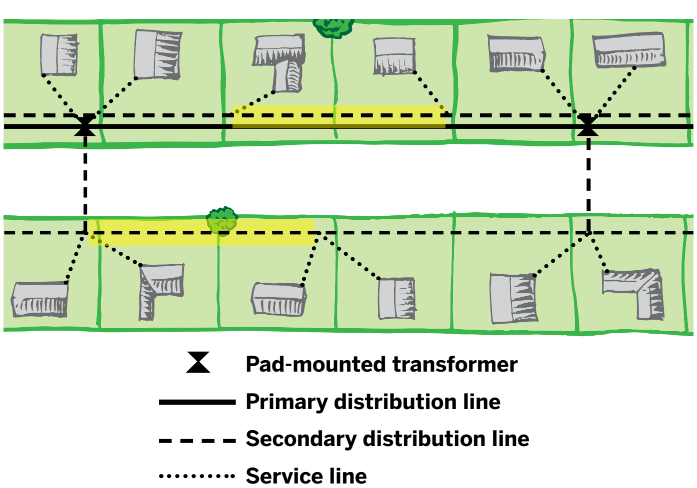



Figure 11 on the next page illustrates a typical overhead distribution pole, showing the primary lines, a transformer, an electric service to one home and secondary lines running in both directions to serve multiple homes.

The final step in the delivery of power from the utility to the customer is the service line, or drop,[14] from the common distribution facilities in the public right of way to the customer's meter. That line may be overhead or underground. Even where the distribution service is overhead, customers may be served by an underground service drop out of concerns for aesthetics or reliability, since underground lines are not vulnerable to damage from wind or trees.

For primary voltage customers, the service drop is a line at the primary voltage, attached to one or more phases of primary feeder. For secondary customers, the service drop may run from the transformer to the customer or from a convenient point along the secondary lines.

14 Since overhead service lines often slope down from their connection on the utility pole to the attachment point on the customer's building, they tend to literally "drop" the service down to the customer.

Figure 11. Secondary distribution pole layout

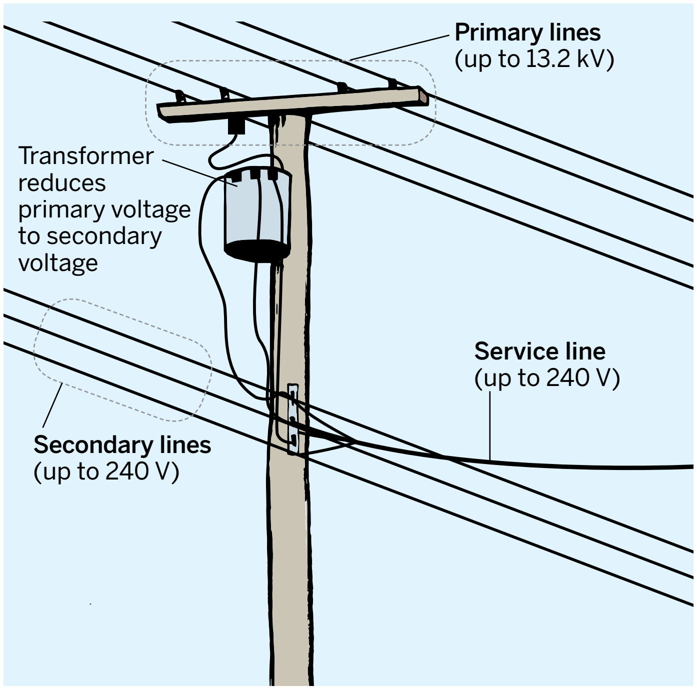
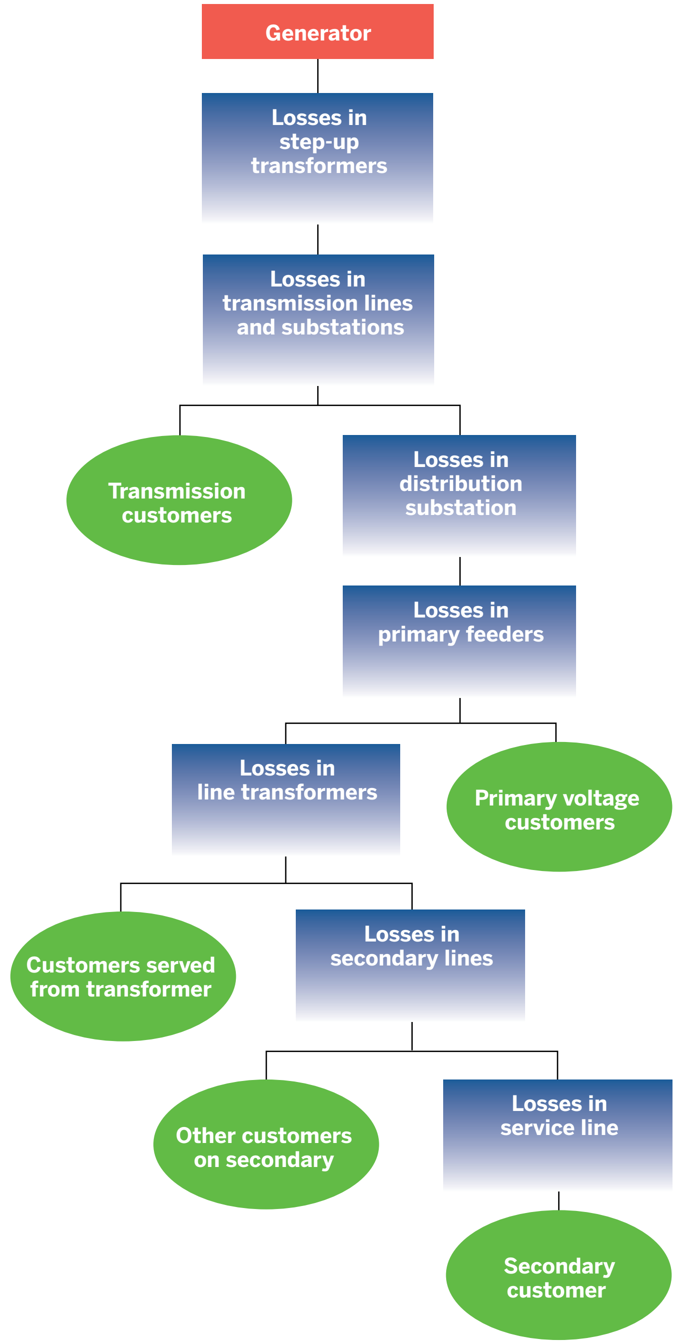



Figure 12. Electric delivery system line losses




## 3.1.4 Line Losses

For most purposes in a cost allocation study, line losses are not broken out as a separate category of costs. However, the physics of energy flowing over transmission and distribution lines can lead to nontrivial costs. A line loss study is an important input into a cost of service study because it helps determine the differential cost allocations to customers served at different voltages.

A small percentage of power is lost in the form of heat as it flows through each component of the delivery system, as discussed at length in Lazar and Baldwin (2011). The losses in conductors, including transmission and distribution lines, are known as resistive loss. Resistive loss varies with the square of the quantity of power flowing through the wire. Because of this exponential relationship between load and losses, a 1% reduction in load reduces resistive losses by about 2%. The levels of conductor losses from the generators to a customer at secondary voltage (such as a residential customer) are illustrated in Figure 12. Transformers have more complex loss formulae because a certain amount of energy is expended to energize the transformer (core losses) and then all energy flowing through the transformer is subject to resistive losses. Average annual line losses typically are around 7%, but marginal losses can be much higher, more than 20% during peak periods (Lazar and Baldwin, 2011, p. 1).

Reducing a customer's load (or serving that load with an on-site generation or storage resource) reduces the losses in the service drop from the street to the customer, the secondary line (if any) serving that customer, the line transformers, the distribution feeder, the distribution substation, and transmission lines and transmission substations. Lower loads, on-site generation and storage also reduce the generation capacity and reserve requirements, meaning that a 1-kW reduction in load at the customer's premises can avoid nearly 1.5 kWs of generating capacity at a central source (Lazar and Baldwin, 2011, p. 7).

### 3.1.5 Billing and Customer Service

Traditionally, metering is considered a customer-specific expense for the purpose of billing. Advanced metering infrastructure is used for a much wider array of purposes, however, such as energy management and system planning. This indicates that broader cost allocation techniques should be used. Historically, meter reading was a substantial labor expense, with meter readers visiting each meter every billing cycle to determine usage. However, utilities with either AMI or AMR technology have either eliminated or greatly reduced the labor expenses involved. Customers that opt out of AMI often incur special meter reading costs, if meter readers are needed for a small number of customers.

Most utilities bill customers either monthly or bimonthly for a variety of related practical reasons. If customers were billed less frequently, the bills for some customers would be very large and unmanageable without substantial planning. If billed more frequently, the billing costs would be significantly higher. Billing closer to the time of consumption provides customers with a better understanding of their usage patterns from month to month, which may help them increase efficiency and respond to price signals. There are exceptions, since many water utilities, sewer utilities and even a few electric utilities serving seasonal properties may render bills only once or twice a year.[15]

Related to billing and metering, there are a range of investments and expenses needed to store billing data and issue bills. Historically, billing data was quite simple, and the cost of issuing bills was primarily printing and mailing costs. With AMI, billing data has grown substantially more complex, and additional system and cybersecurity requirements are needed. Conversely, online billing can lower certain costs and provide easier access to customer data.

The expenses of unpaid bills are known as uncollectibles and typically are included as an adjustment in the determination of the revenue requirement as a percentage of expected bills in order to keep the utilities whole. Bills may go unpaid because of customer financial difficulties, departure from the service territory or any number of other factors. In some jurisdictions, deposits are required to protect utilities from unpaid bills. Utilities often use their ability to shut off electric service to a customer to ensure bill payment, and many jurisdictions implement shutoff protections to ensure that customers are not denied access to necessary or life-preserving services.

Customer service spans a whole range of services, from answering simple questions about billing to addressing complex interconnection issues for distributed generation. These expenses may vary greatly by the type of customer. Many utilities have "key accounts" specialists who are highly trained to meet the needs of very large customers. Large customers typically have more complex billing arrangements, such as campus billing, **interruptible rates** and other elements that require more time from engineering, legal and rate staff, as well as higher management. Some utilities lump these customer services together. The better practice is to keep them separate based on how each rate class incurs costs and benefits from the expenses.

Some utilities also characterize various public policy programs, such as energy efficiency programs, as customer service, but this is typically a mistake because these costs are not related to the number of customers. Instead, they relate to the power supply and delivery system capacity and energy benefits the programs provide.

Some states allow utilities to include general marketing and advertising efforts in rates, but others require shareholders to fund any such efforts. More narrowly targeted energy conservation and safety advertising expenses are often recovered from ratepayers as a part of public policy programs.

### 3.1.6 Public Policy Program Expenditures

States have mandated that utilities make expenditures for various public policy purposes. One of the largest is energy efficiency, but others include pollution control, low-income

15 This is also the case for California customers who opt out of AMI (California Public Utilities Commission, 2014).

customer assistance, renewable resources, storage and hardening of the system to resist storm damage. Each of these cost centers has a place in the cost allocation study, and each must be treated based on the purpose for which the cost is incurred.

### 3.1.7 Administrative and General Costs

Utilities also have a wide variety of overhead costs, typically called administrative and general costs. They include necessary capital investments, known as general plant, and ongoing expenses, typically called A&G expenses. General plant includes office buildings, vehicles and computer systems. A&G expenses include executive salaries, pensions for retired employees and the expenses due to regulatory proceedings. The common thread is that these costs support all of a utility's functions.

## 3.2 Types of Utilities

Utilities differ in terms of ownership structure and the types of assets they own. The many types of electric utility organizations have different characteristics that may lead to different cost allocation issues and solutions. Nationwide, publicly owned utilities typically have lower rates. In 2016, the average residential customer served by public power paid 11.55 cents per kWh, compared with 11.62 cents for co-ops and 13.09 cents for customers served by investor-owned utilities, reflecting a mix of service territory characteristics and differing sources of electricity, costs of capital and tax burdens (Zummo, 2018). Some utilities are also vertically integrated, owning generation, transmission and distribution assets simultaneously, while others own just distribution assets.

### 3.2.1 Ownership Structures

Investor-owned utilities serve about 73% of American homes and businesses and own about 50% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). The regulated utilities that directly serve customers may be part of larger holding companies that include other corporate assets, such as regulated utilities in other states, natural gas assets or totally unrelated enterprises. Unlike utilities owned by governments or by the members and customers, IOUs include a return on investment, specifically a return on equity for shareholders, in the calculation of the revenue requirement. This is typically calculated as the net rate base (gross plant net of accumulated **depreciation**) multiplied by the weighted average rate of return, which is composed of the interest rate on debt and the allowed return on equity. In many states, utility commissions regulate only IOUs.

Publicly owned utilities — including municipal utilities, or munis, and public power districts — serve about 15% of American homes and have about 7% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). Many of the areas served are urban, and municipal utilities often provide other services as well, such as water, sewer and natural gas. These utilities evolved for a variety of reasons but typically are not subject to state or federal income tax (but typically pay many other types of taxes) and do not include a return on equity in rates. For this reason, their rates tend to be lower than those of most IOUs. The state or local governmental entity that sets up this type of utility also determines the governing structure for the utility, which could be an elected or appointed board. Typically this board will hire a professional manager to oversee the utility. Many municipal utilities also determine their annual revenue requirement on a cash flow basis, which can lead to greater annual variability. In most cases, state public utility commissions have little or no authority over munis and public power districts.

Electric cooperatives are nonprofit membership corporations or special purpose districts that provide service to about 12% of Americans and own about 42% of electric distribution circuit miles (National Rural Electric Cooperative Association, 2017). They also serve more than half of the land area in the U.S. They mostly serve areas that IOUs originally declined to serve because expected sales did not justify the cost, given their shareholders' expectations for rates of return and the required investment. Some cooperatives still serve thinly populated rural areas with few large loads. Others have seen their service territories transformed to booming suburbs or industrial hubs. These entities are also exempt from federal and state income tax and do not need to include a return on equity in the revenue requirement. Unlike municipal utilities, however, cooperatives cannot issue tax-exempt debt. Cooperatives do have flexibility to offer other services to their customers, such as broadband internet, appliance sales and repair, and contract billing and collection. Many cooperatives operate in areas with limited alternatives, and they tend to have good relationships with their member customers. An increasing number of electric cooperatives are building on these assets by entering the solar installation and maintenance field. In most states, cooperatives are entirely self-regulated, with a board being elected by the members. About 16 states regulate cooperatives, often less rigorously than they regulate IOUs (Deller, Hoyt, Hueth and Sundaram-Stukel, 2009, p. 48). This is because any "profits" remain with the member-owned cooperative and members can affect decision-making through board elections.

### 3.2.2 Vertically Integrated Versus Restructured

Vertically integrated utilities have very different cost structures than utilities in states where the electricity industry has been restructured. Vertically integrated utilities provide complete service to customers, including generation, transmission and distribution service, and their mix of resources and cost elements can be extensive. Generation costs may include utility-owned resources, long-term contract resources, short-term contract resources, storage resources, and spot market purchases and sales. Transmission costs may include resources that are utility-owned; jointly owned with other utilities; owned by transmission companies purchased on a short-term or long-term basis; or purchased through long-term arrangements with an **independent system operator** (ISO), **regional transmission organization** (RTO), federal power marketing agency (e.g., the Bonneville Power Administration in the Northwest and the Tennessee Valley Authority in the Southeast) or other transmission entity.

For regulated utilities in **restructured states**, some of these cost elements will be missing. In most cases, the regulated utility will not own any generation assets. The regulated entity may serve certain functions with respect to power supply, such as the procurement of **default service** (also called standard service offer) for customers who do not choose a non-utility retail electricity supplier. However, these costs should be kept out of the cost of service study and cost allocation process and recovered within default power supply charges or as fees to retail electricity providers. In some restructured states, the regulated utilities still own certain types of transmission as a part of the regulated entity, which is subject to the traditional cost allocation process. In other states, transmission assets have been completely spun off into other entities. In many cases, the regulated utility is allowed to include these transmission costs as an allowed operating expense in determining the revenue requirement.

Depending on the mix of assets the regulated utility owns and the assets and operations of the larger holding company, which could span multiple states and even multiple countries, more complex jurisdictional allocation work may be necessary. The principles for jurisdictional allocation of generation and transmission, as well as billing and customer service, general plant and A&G expenses, are similar to those used for class cost allocation but do not have to be the same. Distribution investment costs generally are assigned to the jurisdiction where the facilities are located. Jurisdictional allocation is typically done as a part of the revenue requirement process and does not flow into the cost allocation process.

### 3.2.3 Range of Typical Utility Structures

Between the different ownership models and the mix of assets owned, there are dozens of different utility structures across the country. However, certain models are more common in particular areas:

- Nearly all IOUs outside of the restructured states are vertically integrated, owning and operating generation, transmission and distribution systems and billing customers for all of these services. Some municipal and public power entities are also vertically integrated, as well as a handful of large cooperative utilities.
- Generation and transmission (G&T) utilities own and operate power plants and often transmission lines, selling their services to other utilities (especially **distribution utilities**) and sometimes a few large industrial customers. A large portion of cooperative utilities are served by G&T cooperatives, typically owned by the distribution co-ops.

Several states have municipal power joint action agencies that build, buy into or purchase from power plants and may own or co-own transmission facilities. Many IOUs provide these services to municipal and cooperative utilities but are predominantly vertically integrated utilities serving retail customers.

- Flow-through restructured utilities operate distribution systems but do not provide generation services, leaving customers to procure those from competitive providers. Since generation prices are either set by a retail supplier in an agreement with a specific customer or determined by class from the bids of the winning suppliers in utility procurements for default service, generation cost allocation is not normally a cost of service study issue for these utilities.
- Distribution utilities own and operate their distribution systems but purchase generation and transmission services from one or more G&T cooperatives, federal agencies, municipal power agencies, merchant generators or vertically integrated utilities or through an organized market operated by an ISO/RTO. Outside of restructured states, most distribution-only utilities are municipals or cooperatives. The cost allocation issues for these utilities are similar to those for vertically integrated utilities, with the complication that the loads driving the G&T costs may be different from the loads used in setting the charges to the distribution utility.
- Some transmission companies solely own and operate transmission systems, generally under the rules set by an RTO. Their charges may be incorporated into the retail rates of distribution and flow-through utilities. In many cases, these transmission companies are subsidiaries of larger holding companies that own other electricity assets.

# 4. Past, Present and Future of the U.S. Electric System

Chapter 3 described the basic elements of the electric system in the United States today, but these elements developed out of a 130-year history of twists and turns based on technology, fuels, regulations and even international relations. Understanding the basics of these developments and how and why today's system was formed is relevant to several important cost allocation issues discussed later in this manual. With respect to cost allocation, four primary results of these changes are worth noting:

- A shift from fuel and labor costs to capital costs.
- The transition of new generation to non-utility ownership.
- Significant levels of behind-the-meter **distributed energy resources** (DERs), including rooftop solar.
- Significant increases in the availability, quality and granularity of electric system data.

## 4.1 Early Developments

Electricity generation and delivery started in the late 19th century with three essentially parallel processes:

- Privately owned companies built power plants and delivery systems in cities and near natural generator locations, starting with small areas close to the plants.
- Industrial plants built their own generation and connected other customers to use excess capacity.
- Municipalities set up their own systems, sometimes starting with the purchase of a small private or industrial facility, to serve the population of the city or town.

Initially, these utilities operated without regulation and competed with other fuels, such as peat, coal and wood, which were locally supplied. Municipalities had internal processes to set prices, but private utilities were able to charge whatever prices they wished. In this initial period, some cities did impose "franchise" terms on them, charging fees and establishing rules allowing them to run their wires and pipes over and under city streets. Multiple utilities emerged in some cities and competed against one another, which led to the building of duplicative networks of wires in many areas. These duplicative networks were aesthetically displeasing and considered by many to be economically wasteful. Relatively quickly, however, the natural monopoly characteristics led to the bankruptcy of many utilities or acquisition by a single dominant firm in each city.

**Figure 13. Pearl Street Station, first commercial power plant in the United States**

Source: Wikipedia. *Pearl Street Station*

In New York City, the winning utility, founded by Thomas Edison, eventually became the aptly named Consolidated Edison, or ConEd. Figure 13 depicts Edison's first generating station. New York established the first state economic regulation of electric utilities in 1900, and it spread widely from there. In New Orleans, the city remains the regulator of the IOU; its regulatory activity predated the creation of the state commission that regulates all IOUs operating outside of New Orleans.

## 4.2 Rural Electrification and the Federal Power Act

In the early period, regulatory authority over electric utilities was primarily exercised by states. In 1935, Congress passed the Federal Power Act, which vastly expanded the jurisdiction of the Federal Power Commission (now FERC) to cover interstate electricity transmission and wholesale sales of electricity. However, most economic regulation remained under the jurisdiction of state utility commissions, including authority over retail prices.

By the 1930s, most urban and suburban areas had access to electric service, but most rural areas did not. The Rural Electrification Act passed Congress in 1936, creating the Rural Electrification Administration to finance and assist the extension of service to rural areas through electric cooperatives, the Tennessee Valley Authority, various forms of public power districts and some state-sponsored utilities. The initial financing included significant federal support in the form of grants, technical assistance and very low-interest loans. A handful of states, including New York, North Carolina and Oklahoma, set up their own state power authorities to develop hydro facilities[16] and provide low-cost energy for economic development and other local priorities.

## 4.3 Vertically Integrated Utilities Dominate

By 1950, 90% of rural America was electrified, and access to electric service became nearly universal across the United States. Nearly all electric service was provided by vertically integrated utilities — which owned or contracted for power plants, transmission and distribution within the same corporate entity — or by municipal entities or cooperatives. The boundaries of service between different utilities became roughly stable in this time period and reveal the unique trends in each utility's development.

Many investor-owned utilities, especially in the Midwest and West, developed service territories that look like octopuses, with major urban areas and industrial loads connected by tentacles following the paths of transmission lines.[17] These utilities made business decisions to extend service to particular geographic areas where they believed the potential sales revenues would justify the cost of investment in transmission or distribution and still cover the additional costs of generation and customer service necessary to serve the load.[18] In each case, the utility expected that the sale of electricity would generate enough revenue to justify this expenditure.

Figure 14 on the next page shows the service territories of the Texas investor-owned utilities, illustrating these patterns (Association of Electric Companies of Texas Inc., 2019). Similar patterns are evident in the service territory maps of Minnesota, Delaware, Ohio, Oregon, Washington and Virginia. IOUs and municipal utilities generally serve densely populated areas, while cooperatives and public power districts, typically created and incentivized under the Rural Electrification Act, serve less dense areas.

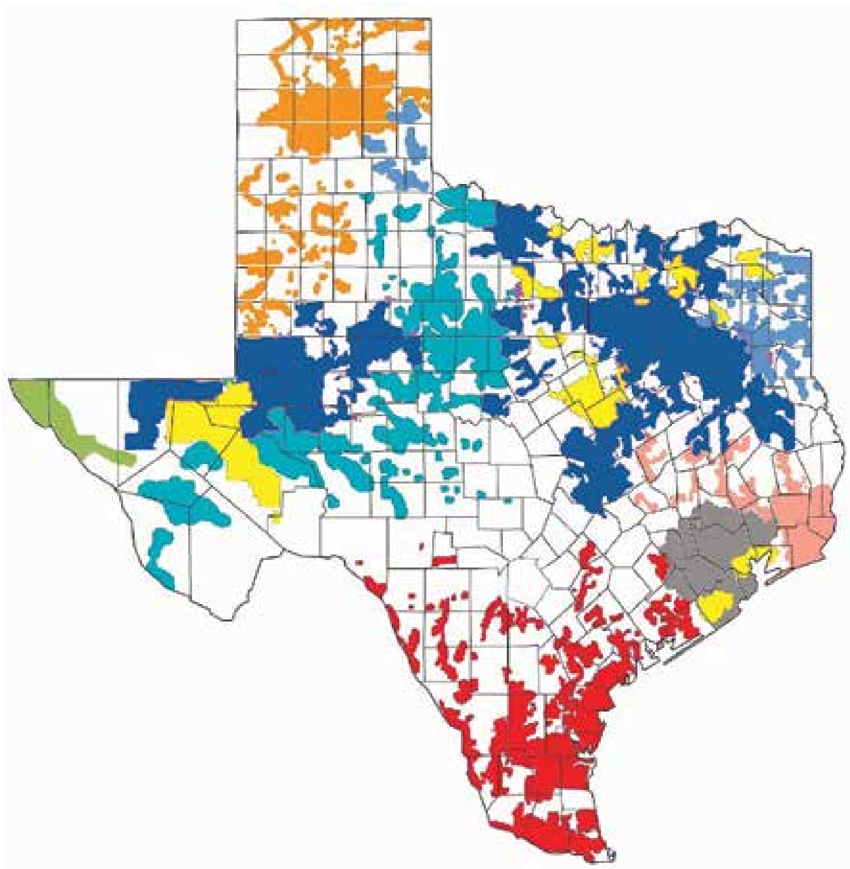
In some states, IOUs do serve some sparsely populated areas. This is often the result of a franchise grant by a municipality or a state mandate for service throughout an identified area to avoid islands where service is unavailable. The cost of this rural service is, to the utility, a price it must pay for access to the more densely populated area for a viable business, although ratepayers typically bear the higher costs of service.

16 Some of these state entities eventually assumed ownership of other types of generation.

17 In some states, such as Massachusetts, most of Maryland, Rhode Island and New Jersey, the IOUs serve large contiguous areas, regardless of density, due to historical and legal conditions in each state. In essence, the utilities incurred an obligation to serve less-developed areas as a price of obtaining authority to serve more densely populated areas.

18 In some cases, the IOU picked up dispersed service territory during the process of acquiring the assets of other power producers or to obtain state or local licenses for generation or transmission facilities.

**Figure 14. Investor-owned electric utility service territories in Texas**




Source: Association of Electric Companies of Texas Inc. (2019). *Electricity 101*

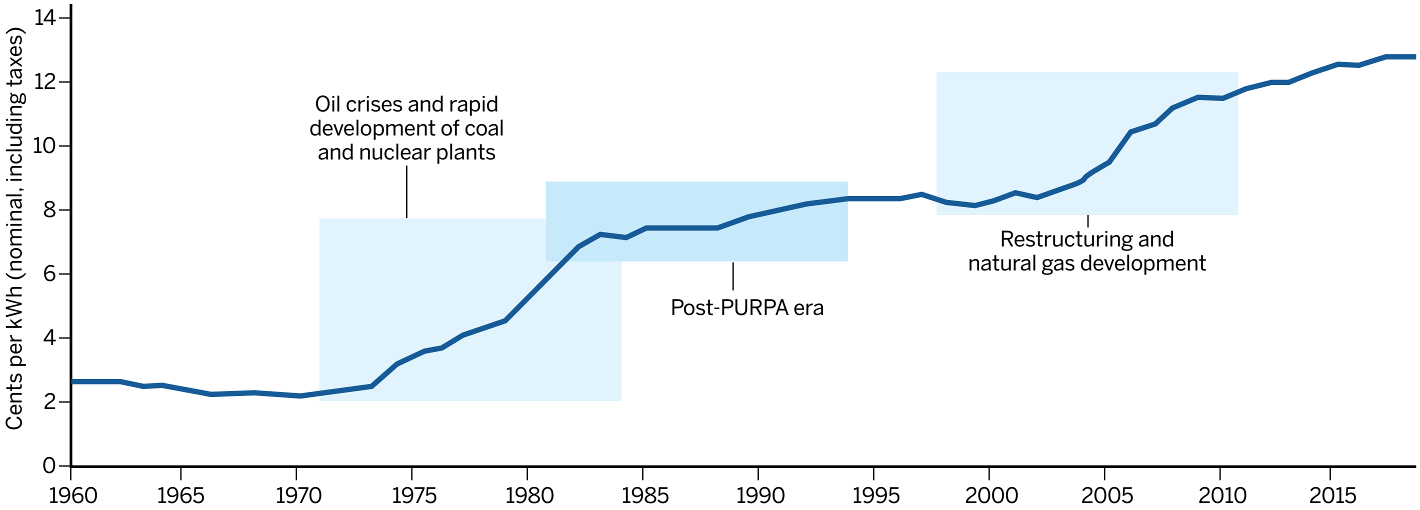
A cost analyst may need to examine these costs carefully to avoid shifting them to specific customer classes and to spread these costs systemwide.

## 4.4 From the Oil Crisis to Restructuring

From the 1950s to the early 1970s, electric sales skyrocketed due to a wide range of new electric end uses, and prices were relatively stable. However, the cost structure of the utility industry changed drastically after the 1974 oil crisis. Demand fell rapidly, particularly in locations where oil was used to generate electricity, in response to large price increases and fuel shortages. Natural gas prices, which had been partly regulated, were gradually deregulated over the next decade, but natural gas was thought to be in short supply and available only for certain uses. No new baseload power plants running more than 1,500 hours a year could be run on oil or natural gas under the Powerplant and Industrial Fuel Use Act of 1978, which was later repealed. In addition, generation of electricity with natural gas was to be prohibited at existing plants by 1990, with an exception for certain combined heat and power (CHP) facilities (Gordon, 1979). This law accelerated a trend toward the construction of large capital-intensive nuclear and coal power plants across the country in order to get away from the use of oil and natural gas for electricity. The confluence of all these trends, including high oil prices and expensive capital-intensive plants entering the rate base, led to major increases in electricity prices, as depicted in Figure 15 on the next page using U.S. Energy Information Administration data (2019).

Congress also passed PURPA in 1978, which included provisions intended to open up competition in the provision of electricity and to reform state rate-making practices. On the competition side, PURPA required electric utilities to purchase power from independent producers at long-term prices based on **avoided costs**. With regard to state rate-making practices, PURPA also required state commissions

**Figure 15. US average retail residential electricity prices through 2018**




Data source: U.S. Energy Information Administration. (2019, March). *Monthly Energy Review*

to consider a series of rate-making standards, including cost of service. This standard was widely adopted, but neither PURPA nor the state commissions defined "cost of service."[19] PURPA also requires some method to assure consumer representation in the consideration of rate design, through either a state consumer advocate or intervenor funding.

The widespread end result was low-cost energy generation (particularly after the fall in oil and gas prices in 1985-1986) and excess capacity in the 1980s, meaning the wholesale price of power was often much lower than full retail rates, even the supply portion of those rates. As a result, large industrial power users and municipalities began demanding the right to become wholesale purchasers of electricity. Given the changes in fuel markets, Congress repealed the limits on natural gas usage for electricity in the Natural Gas Utilization Act of 1987.

During the 1980s, major changes occurred in the telecommunications and natural gas industries, often termed deregulation but more accurately described as restructuring. Following these trends and the demands of larger purchasers for lower rates, Congress passed the Energy Policy Act of 1992.[20] This law called for open access to transmission service and paved the way for restructuring of the electric industry, including organized wholesale markets. In several parts of the country, including Texas and the Northeast, Midwest and West Coast, many states followed these trends and passed restructuring acts in the late 1990s, which required formal separation of certain asset classes and, in some cases, total divestment of generation assets. In several parts of the country, following voluntary criteria articulated by FERC in 1996, independent system operators were created to formalize independent control of the electric system and to administer organized wholesale markets for energy supply. FERC also articulated voluntary criteria in 1999 to form regional transmission organizations, which contain many of the same elements as the earlier ISO requirements (Lazar, 2016, pp. 21-23). There are currently six ISOs/RTOs operating solely in the U.S., two operating exclusively in Canada and one that includes areas in both countries:

- California Independent System Operator (CAISO).
- Electric Reliability Council of Texas (ERCOT).
- Midcontinent Independent System Operator (MISO),

19 The relevant provision of PURPA merely states: "Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs of providing electric service to such class" (16 U.S.C. § 2621[d][1]). This was clarified by the 2005 amendments to include "permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service" (16 U.S.C. § 2625[b][1]).

20 Pub. L. 102-486. Retrieved from https://www.govinfo.gov/content/pkg/STATUTE-106/pdf/STATUTE-106-Pg2776.pdf

spanning from North Dakota through Michigan and Indiana and down to Louisiana while also including the Canadian province of Manitoba.

- ISO New England (ISO-NE).
- New York Independent System Operator (NYISO).
- PJM Interconnection, spanning from New Jersey down through part of North Carolina and extending west through West Virginia and Ohio, while also including the Chicago area.
- Southwest Power Pool (SPP), spanning from North Dakota down through Arkansas, Oklahoma and northern Texas.
- Alberta Electric System Operator (AESO).
- Independent Electricity System Operator (IESO) in Ontario.

Organized wholesale markets for energy supply provide for structured competition among owners of power plants while meeting reliability and other constraints. These markets provide a nominal framework for competition but are in actuality much more deliberately constructed than any actual competitive markets that do not have the same reliability obligations. Cost analysts should pay careful attention to whether wholesale market structures and tariffs truly reflect cost causation.

In some states, retail customers were also given the option of choosing a new retail electricity supplier for the energy component of their rates, typically with utility-procured "basic" or default energy service as the more widely used option.[21] FERC regulates ISOs and RTOs, as well as the organized wholesale markets they run. However, each traditional regulated utility retained ownership of the distribution system as a natural monopoly regulated by the state, and states are the primary regulatory entity for retail electricity suppliers.

Several more states were either in the beginning stages of restructuring or contemplating restructuring in the early 2000s when a backlash from events in restructured states halted this trend. Chief among these events was the California energy crisis, where a drought-induced supply shortfall enabled energy traders to manipulate newly formed energy markets. In combination with infrastructure limitations and other features of the new California rules, this led to high wholesale market prices, the bankruptcy of one of the nation's largest utilities and even the recall and removal of California's governor.

## 4.5 Opening of the 21st Century

The beginning of the 21st century has seen another wave of dramatic change in the electric sector. Restructured areas have seen significant changes in investment patterns. New natural gas combined cycle plants have become a much more important source of generation. Aided by a drop in natural gas prices due to innovations in drilling technology, they have been able to outcompete other types of generation. This has meant significant retirements of other types of generation, starting with older oil and coal units, which have also been affected by new pollution control requirements over the last several decades. More recently, nuclear plants built in the 1960s through 1980s have started to be retired, or their owners have claimed that low energy market prices require additional financial support to enable their continued operation.

In addition, global market developments and federal, state and local policies for renewable generation, as well as energy efficiency and demand response, have led to significant expansions in new resources that have zero pollution and low marginal costs. Many states have adopted **renewable portfolio standards** (RPS) to accelerate the adoption of new renewable technologies, sometimes with requirements for solar or other specific technologies. Storage technology innovation has further increased options for grid flexibility and reliability. New technologies to monitor and manage the electricity grid have also become much more prevalent as a result of continued innovation, cost decreases and policy support.

Some jurisdictions are looking at how to maximize the benefits of customer-sited investments in energy efficiency, energy management and distributed generation. Notable examples are the Reforming the Energy Vision process in

21 Texas is the exception, without any option for utility-provided energy supply service.

New York, E21 in Minnesota and the distribution resources plan proceedings in California. These efforts may even extend to new market structures at the retail level and new platforms for customers and third parties to exchange data and to offer and receive new types of services.

Changes in the electricity system affect many parts of the cost allocation process.

First, a utility cost study performed in 1980 might have placed 70% of the utility revenue requirement in the categories of fuel and purchased power, which are generally considered short-run variable energy-related costs. Since that time, capital has been substituted for fuel, in the form of wind, solar, nuclear and even high-efficiency combined cycle units running on low-cost natural gas. Many variable labor costs for customer service and distribution employees, including meter readers, have been displaced with capital investments in distribution automation and smart grid technologies. As energy storage evolves, even peak hour needs may be met with no variable fuel costs incurred in the hour when service is actually provided. Instead, power may be generated in one period with a variable renewable resource with no fuel cost[22] and saved for a peak hour in a storage system with almost no variable operating costs.

Second, a significant share of electricity generation is now owned by non-utility investors. Some of this shift is driven by federal tax code provisions, some is due to the emergence of specialized companies that build and operate specific types of power generating facilities, and some is due to public policy decisions to limit ownership of generating resources by traditionally regulated utilities. As a result, costs attributable to these sources of generation are primarily the cost of the energy — which is not divided up into capital costs, maintenance costs, etc., as it was when the generation plant was owned and operated by the utility. The 2005 amendments to PURPA, which state that time-differentiated cost studies must be considered, provide an imperative to think carefully about how to assign costs to time periods.

Third, a range of supportive state and federal policies, combined with falling costs, have led to major increases in DERs, notably rooftop solar. Advanced energy storage may be the next great wave on this front, enabling both widespread energy management and backup power resources.

Fourth, today's sophisticated data and analytical capabilities present regulators and analysts alike with a wide range of new choices. Several decades ago, analysts were limited to simple categorizations and shortcuts. This includes the traditional division of costs as customer-related, demand-related or energy-related. Regulators are no longer bound by these limitations and should seek to improve on dated techniques.

22 For example, Xcel Energy has put forward a "steel for fuel" program, which substitutes wind and solar facilities for fuel-burning power plants (Xcel Energy, 2018, p. 5).

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# Part II:

# Overarching Issues and Frameworks for Cost Allocation

# 5. Key Common Analytical Elements

Several key analytical processes and decisions must be made regardless of the overall framework and specific methods used for cost allocation. These common analytical elements include:

- Cost drivers: What are the key factors that lead different types of costs to be incurred?
- Determining customer classes: How many classes of customers should be categorized separately, and how is each class defined?
- Load research and data collection: What are the key patterns of load, delivery and generation that need to be recorded and analyzed? For any key data that are not tracked comprehensively, is sampling or another approach used?

In any individual rate case, these issues may not be litigated at great length, and many or all parties may rely on past practices and precedent. But the decisions made on these issues historically by each public utility commission can have important consequences in the present, particularly as changes to technology and the regulatory system undermine the basis of past assumptions.

## 5.1 Cost Drivers

Effective cost allocation and rate design require the identification of central cost causation factors, or cost drivers. Within these processes, it is important to identify relatively simple metrics (e.g., energy use in various periods, demand at various times, numbers of customers of various types) that can be associated with the various customer classes. The cost allocation process, by its nature, approximates cost responsibility and is not a tool of exceedingly precise measurements.

One crucial underlying reality is that customers use electricity at different times, leading to the concept of **load diversity**. Load diversity means the shared portions of the system need to be sized to meet only the **coincident peak** (CP) loads for combined customer usage at each point of the system,[23] rather than the sum of the **customers' noncoincident peak (NCP) loads**.[24] This diversity exists on every point of the system:

- Customers sharing a transformer have diverse loads.
- Loads along a distribution feeder circuit have diversity.
- Multiple circuits on a substation have diversity.
- The substations served by a transmission line have load diversity.
- Individual utilities in an ISO territory or regional transmission interconnection have diversity.

Diversity of load means the actual electricity system is significantly less expensive than a system that would be built to serve the sum of every customer's individual NCP. Holding **peak load** for a customer constant, this also means that a customer with load that varies over time is effectively much cheaper to serve than a customer that uses the same peak amount at every hour. The former customer can share capacity with other customers who use power at other times, but the latter cannot.

Another important reality is that the accounting category to which a cost is assigned does not determine its causation. An expense item may be due to energy use, peak demands or number of customers; the same is true for capital investments. Capital costs and other expenses that do not vary with short-run dispatch changes are referred to as fixed costs by some analysts, and some cost of service studies assume that

23 As explained throughout this section, the critical coincident peak load may be a single peak hour but more typically is some combination of loads over multiple hours.

24 Several other terms are used for individual customers' noncoincident peak demand, including "undiversified maximum customer demand." Unfortunately, both "NCP" and "maximum customer demand" can also be used to refer to various class peaks, particularly when used with modifiers. This manual will use "customer NCP" to refer to individual customer peaks and "class NCP" to refer to aggregated peaks by class, often specifying the level of the system for the relevant class NCP. Class NCP is sometimes referred to as the maximum class peak, maximum diversified demand or other similar terms.

these notionally fixed costs cannot be driven by energy use. As discussed in the text box on pages 78-79, this assumption is incorrect. Utilities make investments and commit to "fixed" expenses for many reasons: to meet peak demands, to reduce fuel costs, to reduce energy losses, to access lower-cost energy resources and to expand the system to attract additional business. As a result, this manual will use the phrase "dispatch O&M costs" to reflect operations and maintenance costs that vary directly with generation output and "nondispatch O&M costs" for O&M costs that are incurred independently of output levels.

## 5.1.1 Generation

There are several different categories of generation costs, with different lengths of time for the commitment. Depending on the technologies in question, long-term capital costs, nondispatch O&M costs and per-kWh fuel costs are substitutable — that is, a wind generator with a battery storage system involves more capital cost and lower operating cost than a natural gas combustion turbine unit with the same output.

The longest-lived category of generation costs is capital investment in generation facilities, which are often depreciated on a 30-year timeline and can last even longer. Once the investment is made, the depreciation expense typically will not vary over that time. Of course, a generation facility can be permanently shut down (retired), temporarily shut down (mothballed) or repurposed before the depreciation period is over. Different costs and benefits may be incurred for each of these three options. It is also possible for a plant's life to be recalculated at some point, with an appropriate change in the depreciation schedule and the annual depreciation expense.

There can be significant capital investments and nondispatch O&M costs that are incurred on an annual or monthly basis, which may not vary directly with the numbers of hours the facility operates. There are also capital investments that are driven by wear and tear, rather than the passage of time.[25]

The shortest-term variable costs for utilities are mostly fuel costs and the portions of power purchases that vary with energy taken. In addition, some O&M costs are usually considered variable with output: the costs of some consumable materials (especially for pollution control equipment), as well as the costs of replacements (such as lubricants and filters) and overhauls that are required after a specified amount of output, equivalent full-load hours of operation or similar measures.[26]

In many cases, utilities classify costs based on accounting data and administrative convenience, rather than the underlying reasons why the costs were incurred and why any capital investments are still part of the system. For example, utilities may treat some O&M and interim capital additions as variable and energy-related for one set of purposes, such as rate design or evaluation of potential generation resources, but treat the same costs as demand-related for cost allocation purposes for simplicity. Cost of service studies are normally driven primarily by accounting data that do not readily differentiate dispatch O&M costs from nondispatch O&M costs and capital additions.

Similarly, other costs, such as pollution controls and ash handling and disposal at coal plants, include significant long-run investments that were specifically incurred to support the energy generation process and generally should be treated as energy-related. These investments would not be needed or would be less costly either if the plant were run less often or if the fuel were less polluting.

### Short-Run Variable Generation Costs

The short-run variable cost of power generation is typically straightforward, primarily entailing a mix of fuel costs, dispatch O&M costs for utility-owned generation and purchased power. As a result, the drivers of these costs are typically fuel prices, market prices for energy and any ongoing contracts the utility has. Utilities can hedge the risk of short-term energy generation costs through a wide range of means, including futures contracts for fuel and power.

The short-run variable costs of some generation facilities, including storage and dispatchable hydro, are very low. Storage facilities require the operation of other resources (which may well have variable costs) to charge them. Dispatch

25 These costs are comparable to tire replacements that are caused by wear and tear closely correlated with miles driven.

26 These costs are comparable to the costs of automotive oil changes and routine services that are the consequence primarily of miles driven.

decisions for storage and dispatchable hydro resources are typically made to maximize the benefits from the limited supply of other time-shiftable generation resources.

Prior to PURPA, most long-term purchased power contracts had separate capacity and energy elements. These were mostly for fuel-dependent power plants. This rate form allowed the owner to obtain capital cost recovery in a predictable payment and the receiving utility to control the output as needed to fit varying loads, paying for short-run variable costs as incurred. Today many power purchase contracts are expressed entirely on a volumetric basis, based on an expected pattern of output. This change in how contracts are priced in the wholesale market does not dictate any particular approach to how costs are allocated in the retail rate-setting process.

### Generation Capacity Costs

Beyond these energy needs, most regions of the United States also plan around the amount of shared generation capacity needed, and these processes can drive a significant amount of generation costs. The amount of capacity required by a utility system, typically denominated in **megawatts** (MWs) or gigawatts at the time of the system coincident peak, determines whether the utility should retire existing plants, add new resources or delay planned retirements, or keep the system as it is. All those decisions have costs and benefits. This determination may be made by an ISO/RTO, a holding company or other aggregation of interconnected load.

Although the typical planning procedures used to date by utilities and ISOs have often served their original purposes to measure the least-cost resources available at the utility system level, these procedures often oversimplify important aspects of overall capacity and reliability issues. The key principle is that reliability-related costs are not all "caused" by one hour or a few hours of demand during the year. A system must have some form and level of capacity available at all hours. Loss-of-energy expectation[27] studies generally show that adding capacity at any hour to a system, even **off-peak** hours, has a small but discernible beneficial impact on reliability. Many resources can be justified only if all of the attributes are considered, including contribution to meeting peak demand and contribution to meeting other needs such as fuel cost reduction.

The typical vertically integrated utility calculates the installed capacity requirement by determining what amount of existing and new capacity will provide acceptable reliability, measured by such statistical parameters as the mathematical expected value of the number of hours in which it cannot serve load or of the amount of customer energy it will not be able to serve in a year, due to insufficient available generation. Those expected values are computed from models that simulate the scheduling of generation maintenance and the random timing of forced outages for many potential combinations of outages and load levels. In large portions of North America, the capacity requirement is determined regionally by an ISO/RTO and then allocated to the load-serving entities, transmission control areas or utilities.[28]

Required reserves are usually expressed as the percentage **reserve margin**, which is:

$$(\text{capacity} - \text{peak load}) \div \text{peak load; or}$$
$$(\text{capacity} \div \text{peak load}) - 1$$

Capacity may be defined as installed capacity, demonstrated capacity or unforced capacity (installed capacity reduced by the resource's forced outage rate). There may be special provisions to recognize that an installed MW of solar, wind or seasonal hydro capacity is not equivalent to an installed MW of combustion turbine capacity with guaranteed fuel availability or a MW of battery storage capacity located at a distribution substation. Capacity requirements may also be satisfied with curtailable load, energy storage or expected price response to peak pricing. The cost of capacity to meet a very short-term need is very different from the cost of **baseload capacity** that serves customers around the clock

27 Different analysts refer to related measures as loss-of-load hours, loss-of-load expectation, expected unserved energy and loss-of-load probability.

28 Some of the utilities in the ISOs/RTOs are restructured and do not provide generation services, so the cost of service study need not deal with generation costs. However, all the utilities in the SPP and most of those in MISO are vertically integrated, as are some jurisdictions in PJM (West Virginia, Virginia, Kentucky and the PJM pieces of North Carolina, Indiana and Michigan) and ISO-NE (Vermont) and municipal and cooperative utilities in most restructured jurisdictions.

and throughout the year, and the cost analyst must be aware of these differences.

Peak load is generally the utility's maximum hourly output requirement under the worst weather conditions expected in the average year (e.g., the coldest winter day for winter-peaking utilities or the hottest summer day for summer-peaking utilities). In the ISOs/RTOs, the peak load is usually the utility's contribution to the actual or expected ISO/RTO peak load. Although the reserve margin is often stated on the basis of a single peak hour as a matter of measurement convention, the derivation of the reserve margin takes into account far more information than the load in that one hour. The most important parameters in determining the required reserve margin are the following:

- **Load shape**, especially the relationships among the annual and weekly peaks and the number of other hours with loads close to the peaks. The system must have enough reserve capacity to endure generation outages at the high-load hours. The near-peak hours matter because the probability of any given combination of outages coinciding with the peak hour is very low, but if there are hundreds of hours in which that combination of outages would result in a supply shortage, the probability of loss of load would be much larger.
- Maintenance requirements. Utilities attempt to schedule generator maintenance in periods with loads lower than the peak, typically in the autumn and spring, and occasionally in the winter for strongly summer-peaking utilities and in the summer for strongly winter-peaking utilities. Utilities with both modest maintenance requirements and several months with loads reliably well below those in the peak months can schedule all routine maintenance in the off-peak months while leaving enough active capacity to avoid any significant risk of a capacity shortage in those months. But many utilities have large maintenance requirements (especially for coal-fired and nuclear units) and only modest reductions in peak exposure in the shoulder months. After subtracting required maintenance, the effective reserve margin may be very similar throughout the year, increasing the chance that a combination of outages will result in loss of load. As a result, high loads in any month (or perhaps any week) contribute to the need for installed capacity.
- Forced outage rates. All generation units experience some mechanical failures. The higher the frequency of forced outages, the more likely it is that a relatively high-load hour will coincide with outages, eliminating available reserve and resulting in the loss of load.
- Unit sizes. If all of a system's units were very small (say, under 1% of system peak), the random outages could be expected to spread quite evenly through the year. With larger units, outages are much lumpier, and loss of a small number of large units can create operating problems. Hence, systems with larger units tend to need higher reserve margins, all else being equal.
- Other operating constraints. Although hydro resources have the highest overall reliability, they produce power only when water is available to run them. Some hydro resources are required to be operated for flood control, navigation, irrigation, recreation, wildlife or other purposes, and these other constraints may affect the ability of the resource to provide power at full capacity when system peak loads occur.

Some of the factors in this list affect the reliability value of various types of generation, while others highlight the types of load that increase required capacity reserve levels. A large unit with frequent forced outages may contribute little to ongoing system reliability even though it has a significant nameplate capacity. If such a unit has high ongoing costs that could be reduced or eliminated through retirement, continued operation must primarily be justified by its energy benefits. On the demand side, long daily periods of high loads can mean that many weekday hours (and even some weekend hours) in each month will contribute to capacity requirements, proportionately shifting capacity responsibility toward customers with high **load factors**. Table 2 on the next page summarizes cost drivers for power supply capacity.

The value of capacity is partly a function of the type of capacity and the location of that capacity. Although required capacity (measured in MWs) is determined by demand in a subset of hours, along with the characteristics of the power plants, the cost of capacity (measured in dollars per MW-year) is in large part determined by energy requirements.

In the previous millennium, the cheapest form of

Table 2. Cost drivers for power supply

| Resource type | Purpose | Investment-related costs | Maintenance costs | Fuel costs |
|---|---|---|---|---|
| **Baseload nuclear, geothermal** | Power at all hours | High | High | Low |
| **Coal, intermediate combined cycle** | Power at many hours | Medium | Medium | Medium |
| **Peaking** | Power in peak hours, plus reserves at all hours | Low | Low | High |
| **Hydro** | Power at some or all hours | Very high | Low | Low or none |
| **Wind** | Power at some hours | High | Low | None |
| **Solar** | Power at some hours | High | Low | None |
| **Storage** | Power at peak hours, plus reserves at all hours | High | Low | Low — for purchased kWhs |

capacity to serve peak needs was typically considered to be a combustion turbine. These units had low investment costs and low ongoing O&M expenses but were inefficient and typically used more expensive fuels. These characteristics made them perfect to run infrequently during peak times and for other short-term reliability needs. Conversely, it made sense to make major investments in units with high upfront costs but high efficiency and cheap fuel prices and to run these units nearly year-round. These major investments were driven by year-round energy requirements, not peak loads.

Today, in contrast, the least expensive form of capacity to serve extreme peak loads may not be a generating unit at all. For very low-duration loads, demand response, customer response to critical peak pricing or battery storage may be the least-cost resource to serve a very short-duration peak, sometimes described as a needle peak. The ability to curtail an end-use load saves not only the amount of capacity represented by the reduced load but also the marginal line losses and reserves that would be required to reliably sustain that load. Similarly, the ability to dispatch DERs also avoids line losses that would be required to deliver generated capacity to that location.[29]

## 5.1.2 Transmission

The costs of transmission lines depend on the length of the lines, the terrain they must cover and the amount of power they need to carry at different times, sometimes in either direction. The maximum usage of many transmission lines is not necessarily at system peak hours, and the usage of certain lines can change significantly over time. Carrying more power requires larger conductors, multiple conductors and/or higher voltages, all of which increase costs.

If each load center in a utility's territory had about the amount of generation required to meet its peak load, and the power plants were similar so the utility had no interest in exporting power from one area to another, the transmission system would exist primarily to allow each load center to draw on the others for backup supply when local generation was unavailable. In real utility systems, power plants are often distributed very differently from load, with large centralized plants built to capture economies of scale, often in areas far from major load centers. Generation may be sited remotely away from load for environmental reasons, to facilitate access to fuel and to minimize land costs and land use conflict. Generation plants also tend to vary considerably in fuel cost, efficiency and flexibility; allowing the utility to use the least-cost mix of generation at all load levels may require additional transmission.

By contrast, demand response, energy efficiency and energy storage can be very carefully targeted geographically to provide needed capacity in a specific area without the need for any additional transmission.

Although separating all the causes of the structure of an existing transmission system can be difficult, especially for a

29 The capacity saved can be as high as 1.4 times the load reduced, when marginal line losses and reserves are taken into account. For a detailed discussion of this, see Lazar and Baldwin (2011).

utility whose distribution of load and generation has changed over the decades, decisions about the nature and location of generation facilities can have important effects on the costs of the transmission system.

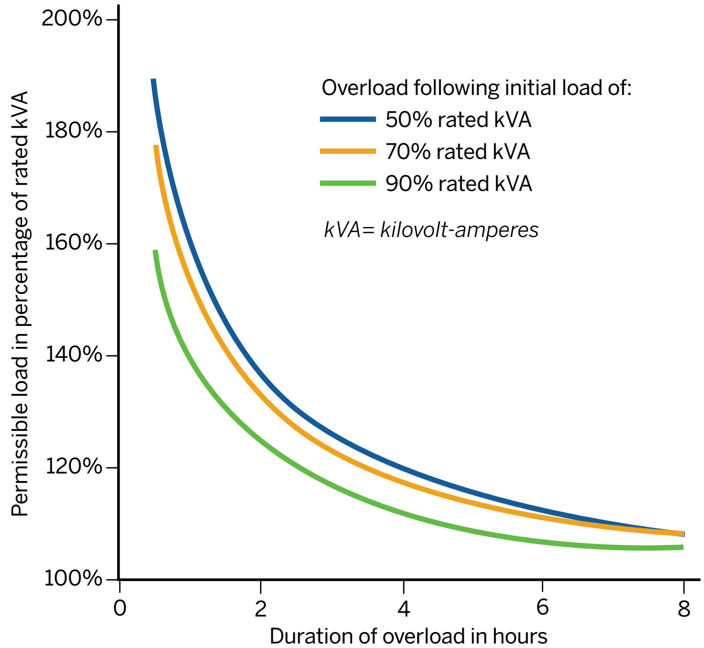
Energy load over the course of many hours also affects the sizing and cost of transmission. Underground transmission is particularly sensitive to the buildup of heat around the lines, so the duration of peak loads and the extent to which loads decline from the peak period to the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a 15-minute peak after a day of low loads as for an eight-hour peak with a high daily load factor. To reduce losses and the buildup of heat from frequent high loads, utilities must install larger cables, or more cables, than they would to meet shorter duration loads.

The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors. A transmission facility normally will have a higher capacity rating for winter than for summer because the heat buildup is ameliorated in cooler weather.

The costs of substations, including the power transformers on which they are centered, are determined by both peak loads and energy use. The capacity of a station transformer is limited by the buildup of heat created by electric energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence, since transformers can typically operate well above their rated capacity for short periods), its internal insulation deteriorates and it loses a portion of its useful life.

Figure 16 illustrates the effect of the length of the peak load, and the load in preceding hours, on the load that a transformer can carry without losing operating life (Bureau of Reclamation, 1991, p. 14). The initial load in Figure 16 is defined as the maximum of the average load in the preceding

**Figure 16. Permissible overload for varying periods**




Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

two hours or 24 hours.[30] A transformer that was loaded to 50% of its rating in the afternoon can endure an overload of 190% for 30 minutes or 160% for an hour. If the afternoon load was 90% of the transformer rating, it could carry only 160% of its rated load for 30 minutes or 140% for an hour.[31]

Similarly, if the transformer's high-load period is currently eight hours in the afternoon and evening, and the preceding load is 50% of rated capacity, afternoon load reductions that cut the high-load period to three hours would increase the permissible load from about 108% of rated capacity to about 127%. Under these circumstances, the transformer can meet higher load without replacement or addition of new transformers.

Short peaks and low off-peak loads allow the transformer to cool between peaks, so it can tolerate a higher peak current. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

30 This specific example is for self-cooled and water-cooled transformers designed for a 55 degrees Celsius temperature rise; other designs show similar patterns.

31 Utilities recognize that the length of overloads is critical to determining whether a transformer needs to be replaced. For example, Potomac Electric Power Co. (Pepco) in Maryland has established standards for replacing line transformers when the estimated average load over a five-hour period exceeds 160% of the rating of overhead transformers or 100% for pad-mounted transformers (Lefkowitz, 2016, p. 41). The company has not found it necessary to establish comparable policies for shorter periods.

Table 3. Cost drivers for transmission

| Connection to (or between) | Purpose | Typical length of line | Investment-related costs | Maintenance costs |
|---|---|---|---|---|
| **Remote baseload generation** | Power at all hours | Long | High | Low |
| **Remote wind or solar** | Power at some hours | Long | High | Low |
| **Peaking resources** | Power in peak hours, plus reserves at all hours | Short | Low | Low |
| **Hydro** | Power at some or all hours | Long | High | Low |
| **Neighbor utilities** | Reserve sharing; energy trading | Short to long | Vary | Low |
| **Substations networked for reliability** | Power at some hours | Short | Medium | Low |
| **Storage and substations** | Power at peak hours, plus reserves at all hours | Very short | Very low | Low |

In a low load factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the 12 monthly peak hours, for example, most transformers would be retired for other reasons before they experienced significant damage from overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads. In this case, the transformer must be sized to limit overloads to acceptable levels and frequency of occurrence commensurate with a reasonable projected lifespan for the asset. If the transformer is often near full capacity with frequent overloads, it will fail more rapidly.

Transmission lines serve many purposes, including connecting remote generating plant to urban centers and enabling the optimal economic interchange of power between regions with different load patterns and generation options. Each transmission segment can be separately examined and allocated on a cost-reflective basis. Table 3 provides examples of this.

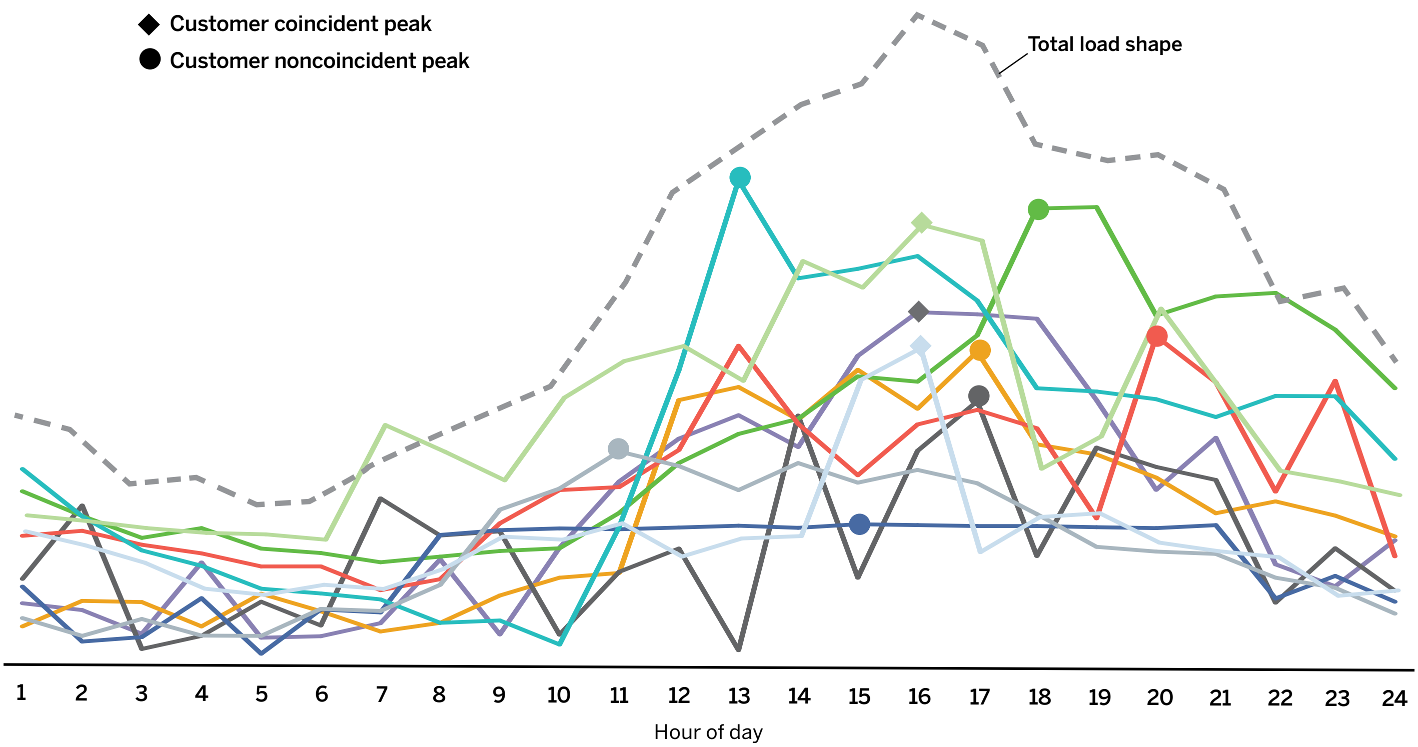
### 5.1.3 Distribution

The factors driving load-related distribution costs are similar to those for transmission. Different components are built and sized for different reasons; some serve the shared needs of hundreds or thousands of customers, while other components are designed to serve a single customer. Substations and line transformers must be larger — or will wear out more rapidly — if they experience many high-load hours in the year and if daily load factors are high. Underground and overhead feeders are also subject to the effects of heat buildup from long hours of relatively high use.

The allowable load on distribution lines is determined by both thermal limits and allowable voltage drop. Higher loads on a primary feeder may require upgrades (raising the feeder voltage, adding a new feeder, reconductoring to a larger wire size, increasing supply from single-phase to three-phase) to maintain acceptable voltage at the end of the feeder. Small secondary customers can be farther from the line transformers than large customers (allowing the utility to use fewer transformers to serve the same load) and can be served with smaller conductors.

As with station transformers, line transformers can handle moderate overloads for relatively short periods of a few hours but will deteriorate quickly if subjected to extended overload conditions. Therefore, the sizing of transformers takes into consideration not only the maximum capacity required but also the underlying load shape. Figure 17 on the next page shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. Although no group of 10 customers is identical to any other group of 10 customers, this demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the

**Figure 17. Summer peak day load from 10 residential customers on one line transformer**




Source: Confidential load research sample

same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day. Furthermore, although not shown in this figure, this coincident peak is only 64% of the sum of the annual noncoincident peaks for the individual customers. It is important to note that a group of 10 residential customers is often less diverse than the combined loads from multiple customer classes, which determine the need for substation and generation capacity upstream of the final line transformer.

It is important to note that the load exceeds 50 kVA for only three hours and is below 40 kVA for 18 hours of this summer peak day. Referring back to Figure 16, under these circumstances, a 50-kVA transformer would likely be adequate to serve this load, because the overload is for only a short period. By contrast, the sum of the maximum noncoincident peak loads of the 10 customers is more than 90 kVA.

A large portion of the distribution investment is driven primarily by the need to serve a geographical region. Once a decision is made to build a circuit, the **incremental cost** of connecting additional customers consists mostly of additional line transformers (if the new customer is isolated from others) and secondary distribution lines. This is true even if those investments may serve multiple customers, particularly in urban and suburban areas. These shared facilities are largely justified by the total revenues of the customers served, not the peak load or number of customers. A particular transmission line, substation or feeder to serve an area could be justified by a single very large load, a small number of large customers or a large number of very small customers.

Nearly every electric utility has a line extension policy that sets forth the division of costs incurred to extend service to new customers. Typically, this policy provides for a certain amount of investment by the utility, with any additional investment paid for by the new customers. These provisions are intended to ensure that new customers pay the incremental cost of connecting them to the system without raising rates to other customers. For most utilities, there is no corresponding credit where new service has a cost that is lower than the

Table 4. Cost drivers for distribution

| Type | Purpose | Investment-related costs | Maintenance costs |
|---|---|---|---|
| **Substations** | Power at all hours; capacity for high-load hours | High | Low |
| **Primary circuits** | Power at all hours; capacity for high-load hours | High | Low |
| **Line transformers** | Power at all hours; capacity for localized high-load hours | Medium | Low |
| **Secondary service lines** | Power at all hours; capacity for localized high-load hours | Medium | Low |
| **Meters: Traditional** | Measuring usage | Low | Low |
| **Meters: Advanced** | Multiple functions | Medium | Low |

average embedded cost of service, a circumstance that results in benefits to the utility and other ratepayers.

The final components in the distribution system are meters, typically installed for all residential and general service customers but not for very predictable loads like traffic signals or streetlights. How to classify the cost is a matter of debate. On one hand, a meter is needed because usage levels vary from customer to customer and month to month, a theoretically usage-related cost. But on the other hand, one meter is needed for every metered customer, and meter costs do not typically vary from customer to customer within a class. In addition, **smart meters** entail both higher direct investment costs and back office investments but provide generation, transmission and distribution system benefits by allowing more precise measurement and control of local loads and more accurate assignment of peaking capacity requirements. Lastly, the cost of current transformers and potential transformers necessary to meter large customers should be included as part of their metering costs — an issue common between embedded and marginal cost methods.[32] Table 4 summarizes cost drivers in the distribution system.

## 5.1.4 Incremental and Complementary Investments

Good economic analysis should distinguish properly between complementary or alternative investments, which substitute for one another, and incremental investments, which add costs to the system.

Customers receive service at different voltages and with different types of equipment. Most of the distinctions among types of equipment represent alternative or complementary methods for providing the same service. For example, various primary distribution feeders operate at 4 kV, 13 kV or 25 kV and may be overhead or underground construction, depending on load density, age of the equipment, local governmental requirements and other considerations. Although the power flowing from generation to a customer served at 25 kV may not flow over any 4-kV feeder, the 4-kV feeders serve the same function as the 25-kV feeders and (in places in which they are adequate) at lower cost.[33] Serving some customers at 4 kV and spreading the feeder costs among all distribution customers does not increase costs allocated to the customers served directly from the 25-kV feeders; converting the 4-kV feeders to a higher voltage would likely increase costs to all distribution customers, including those now served at 25 kV. In this situation, all the feeders should be treated as serving a single function, and all their costs should be allocated in the same manner.

Similarly, most customers served by single-phase primary distribution are served with that configuration because it is cheaper than extending three-phase primary distribution, which they do not require because of the nature of their loads.

32 Current transformers reduce the amperage so a meter can read it. Potential transformers reduce the voltage for meter reading (Flex-Core, n.d.).

33 Conversely, the 4-kV supply to some customers is from transformers fed directly from transmission without using the 25-kV system.

On the other hand, some distinctions in voltage level represent incremental investment:

- Most customers served at distribution voltages cannot take service directly from the transmission system. Even if a transmission line runs right past a supermarket or housing development, the utility must run a feeder from a distribution substation to serve those customers. Distribution in its broadest sense is thus principally an incremental service, rather than an alternative to transmission, needed by and provided to some customers but not all.[34]
- Similarly, most customers who take service at secondary voltage have a primary line running by or to their premises yet cannot take service directly at primary voltage.[35] The line transformers are incremental equipment that would not be necessary if the customers could take service at primary voltage.[36]

These incremental costs should be functionalized so that they are allocated to the loads that cause them to be incurred, while each group of complementary costs (such as various distribution voltages) generally should be treated as a single function and recovered from all customers who use any of the alternative facilities.

In other situations, distinguishing between incremental and complementary costs can be more complicated. Examples include the treatment of transmission equipment at different voltages and the treatment of secondary poles. Many embedded cost of service studies treat subtransmission as an incremental cost separate from transmission and charge more for delivery to customer classes served directly from the subtransmission system or from substations fed by the subtransmission system. For the most part, utilities use lower transmission voltage where it is less expensive than higher voltages, either due to the lower cost of construction relative to the total load that needs to be served by the line or the happenstance that the subtransmission line is already in place. If it is less expensive to serve customers with the lower voltage, it would be inequitable to charge them more for being served at that voltage.

Similarly, distribution poles carrying only secondary lines are less expensive than poles carrying primary lines. If a customer served by a secondary-only pole had to be served at primary voltage instead, the primary pole would be more expensive, and that higher cost would almost certainly be allocated to all distribution customers. Secondary poles (unlike line transformers and most secondary lines) are lower-cost alternatives to some primary poles.[37]

## 5.2 Determining Customer Classes

In addition to administrative simplicity, the purpose of separating customers into broad classes flows from the idea that different types of customers are responsible for different types of costs, and thus it is fairer and more efficient to charge them separate rates. One set of rates for each customer class, based on separate cost characteristics, is the key feature of postage stamp pricing for electric utilities. As a result, it is very important to determine appropriate customer classes with different cost characteristics at the outset of a cost of service study. The number of classes will vary from utility to utility and may vary depending on the costing methodology being used. In addition to equitable cost allocation, different rate structures are often used for different rate classes. For example, residential customer classes generally do not have demand charges today, but most large industrial classes do. This means that decisions regarding the number and type of customer classes can also have rate design implications,

34 In some cases, a distribution substation and feeder can bring service to customers that would otherwise be served by an extension of the transmission system at higher cost. Identifying and accounting for that limited complementary service is probably not warranted in most embedded cost of service study applications.

35 Another way of looking at this relationship is that secondary customers are those for whom providing service at secondary has a lower total cost than providing service at primary. Sharing utility-owned transformer capacity is less expensive than having each customer build its own transformer. See Chapter 11 for a discussion of primary and secondary distribution and their allocation.

36 Although most networked secondary conductors parallel primary lines and are incremental to the primary system, a limited number of secondary conductors extending beyond the primary lines are complementary, because they avoid the need to extend primary lines.

37 Similarly, a portion of the secondary lines replaces primary lines. If the customers that can be served with secondary poles required primary service, the utility would need to extend the primary lines rather than secondary lines. Hence, a portion of the secondary lines is also complementary to the primary system, rather than additive.

although this is not necessarily permanent.

Most utilities distinguish among residential customers, small commercial customers, large commercial customers, industrial customers and street lighting customers. The commercial and industrial classes often are collectively termed general service rate classes. In many cases, general service customers are categorized by voltage levels. Customers served at primary distribution voltage generally do not use, and should not be allocated, costs of secondary distribution facilities, and customers served at transmission voltage generally do not use, and should not be allocated, costs of distribution facilities. Many utilities also separate general service classes with even greater granularity than using simple voltage criteria.

One area where utility practices can vary significantly is whether there is more than one residential class or, alternatively, multiple residential subclasses. Some utilities separate out residential customers based on a measure of size, such as peak demand or energy use. This can be significant in jurisdictions that categorize farms or large master-metered multifamily buildings as residential in a formal sense. Some jurisdictions also create separate classes based on the usage of specific technologies like electric resistance heating. In some jurisdictions, low-income discount customers are treated as a separate rate class.

The creation of multiple residential classes or subclasses is typically justified on cost grounds. There are inarguably many cost distinctions among different types of residential customers, and simple postage stamp cost allocation and rate structures may not capture many of those distinctions. Regulators and utilities have long analyzed the causes of such differences, which vary widely across the country. Some of the distinctions are based on technology (or, more accurately, as a proxy for the load impacts of certain technologies), such as electric space heating, electric water heating, solar or other distributed generation and even electric vehicles. Other distinctions are based on the characteristics of service. Those with relatively large impacts on cost allocation include:

- Single family versus multifamily.
- Urban (multiple customers per transformer) versus rural (one customer per transformer).
- Overhead service versus underground service.

A word of caution is appropriate here. With respect to technology-driven class characteristics such as electric space heat, water heat, vehicles or solar installations, singling out customers based on technology adoption has serious practical and theoretical downsides. Furthermore, addressing one minor cost distinction is likely not fair or efficient if several other major cost distinctions, such as those listed above, are not addressed. It is wiser to consider multiple customer and service characteristics simultaneously to create technology-neutral subclasses for both cost allocation and rate design purposes.

To begin, electric space heating customers are likely to have different load characteristics from the nonheating customers, with significantly more usage and a different daily load shape in the winter. For a winter-peaking system, this could mean that electric heating customers should be allocated proportionately more costs. Conversely, in a summer-peaking system, electric heating customers should be allocated proportionately fewer overall costs. However, this issue, which is essentially a question of a potential intraclass cross-subsidy between types of residential customers, can also be addressed through changes to rate design. Seasonally differentiated rates, if based appropriately on cost causation, can achieve the same distributional impact as separate rate classes for heating and nonheating customers while bringing additional benefits from the improved efficiency of pricing.

The creation of an electric heating rate class can have other implications. In regions where electric heating customers are disproportionately low-income, this decision also has significant equity implications. There can also be environmental repercussions to this choice. Concerns would arise, for example, if electric heating rates promote use of gas and coal in power plants to replace direct burning of gas on-site for heating, which historically was often more efficient on a total energy basis. Recent developments in efficient electric heating, particularly air and ground source heat pumps, may have switched the valence of these questions. In certain areas, higher-income customers may be disproportionately adopting efficient electric heating. And the new electric technologies may now be significantly cleaner and more efficient than on-site combustion of natural gas, particularly if powered by zero emissions electric resources. A seasonal and time-varying cost study and time-varying rates may enable appropriate cost recovery without need for a separate class.

Several states have considered creating a separate rate class for customers with solar PV systems. Because solar customers may have different usage patterns than other customers, this is reasonable to investigate. However, it is not clear that there is a significant cross-subsidy to address, particularly at low levels of PV adoption. Current rate design practices for solar customers in many jurisdictions — such as net metering using **flat volumetric rates**, monthly netting and crediting at the retail rate — are fairly simple. These rate design practices could be improved significantly over time and integrated with broader rate design reforms. For example, a time-varying cost study would allow the creation of more granular time-varying rates so that solar customers pay an appropriate price for power received during nonsolar hours and are credited with an appropriate price for power delivered to the distribution system during solar hours. This would include changes to netting periods, which would reveal more information about how a solar customer actually uses the electric system.

In terms of rate classes for specific technologies, some utilities separate out customers with electric water heating as a proxy for a flat load shape and the potential for load control. In the future, some utilities may seek to make electric vehicle adoption a separate rate class as a substantially controllable load with distinct usage characteristics. However, these technologies may not need consideration as a separate rate class, particularly given efforts to improve the cost causation basis of rate design more generally. Again, time-varying rates will appropriately charge customers with peak-oriented loads and appropriately benefit customers with loads concentrated in low-cost hours or controlled into those hours.

Some utilities have implemented separate rate classes for single-family and multifamily residential customers. There are many reasons to believe that the cost of serving multifamily buildings is substantially lower than serving single-family homes on average:

- Shared service drops.
- Increased diversity of load for line transformers and secondary distribution lines, enabling more efficient sizing.
- Reduced cost of distribution per customer, since no distribution lines are required between customers in the building.[38]
- Reduced coincidence with both summer and winter peak loads because common walls reduce space conditioning use relative to single-family units of the same square footage, and because lighting and baseload appliances such as refrigerators and water heaters (if electric) are a larger percentage of loads for units with fewer square feet.
- Reduced need for secondary distribution lines in cases where the multifamily building can be served directly from the transformer.
- Reduced summer peak coincidence if space cooling is provided through a separate commercial account for the building, rather than as part of the individual residential accounts.
- Reduced costs of manual meter reading, where still applicable.

There may be countervailing considerations in some service territories, such as if multifamily buildings are served by more expensive underground service and single-family buildings are served with cheaper overhead lines. A similar set of considerations may cause some utilities to disaggregate customers by geography, such as those residing inside and outside city limits.[39] Customers in deeply rural areas tend to be more expensive to serve, since they typically are too far from their neighbors to share transformers, require a long run of primary line along the public way, and generally

38 This distinction is important where some distribution costs are classified as customer-related. In those situations, each multifamily building (rather than each meter) should be treated as one customer, as would a single commercial customer of the same size and load.

39 For example, Seattle City Light, a municipal utility, has two rate schedules for most commercial and industrial classes within the city: one for the highly networked higher-cost underground system in the urban core, and another for the balance of the city, plus separate higher rates for the adjacent cities and towns where it provides service. Compare Schedules MDC, MDD, MDS and MDT at Seattle City Light (n.d.). The city of Austin, Texas, also applies different rates to customers outside the city limits (Austin Energy, 2017). In many places, cities impose franchise fees or municipal taxes that make customer bills inside cities higher than those outside cities, even though the cost data may suggest the opposite is more equitable.

have higher unit costs related to lower load per mile of distribution line.[40]

Analysts may want to employ a simple standard for deciding when to divide a subclass for analytical purposes, based on whether the groups are large enough and distinct enough to form a separate class or subclass. One such guideline might be that, if more than 5% of customers or 5% of sales within a class have distinct cost characteristics, differentiation is worth considering. If fewer than that, although the per-customer cost shifts may be significant, the overall impact on other customers will likely be immaterial. If 2% of the load in a class is paying 20% too much or too little, for example, other customers' bills will change only 0.4%. But if 15% of the load is 20% more or less expensive, the impact on other users rises to 3%. The trajectory of these impacts over time can also be relevant.

Although improved distributional equity from additional rate classes is a laudable goal, and indeed advances the primary goal of cost allocation, there are countervailing considerations that may dictate keeping the number of rate classes on the smaller side. First, there are administrative and substantive concerns around adding rate classes, both in litigation at state regulatory commissions and in real-world implementation. Some potential distinctions among customers may be difficult to implement because they involve subjective and potentially controversial determinations by on-the-ground utility personnel. In creating new distinctions, regulators, utilities and stakeholders must all have confidence that there are true cost differentials between the customer types and that there will be little controversy in the application of the differentials. Some analysts object to customer classes based on adoption of particular end uses, although this may serve as a proxy for significantly different usage profiles. Furthermore, some utilities and parties in a rate case may propose rate classes that effectively allow undue discrimination. If the proper data aren't available to scrutinize such claims, either publicly or for parties in a rate case, then this may allow an end-run around one of the significant motivations for postage stamp pricing: preventing price discrimination.

Lastly, as described above for electric heating and solar PV customers, rate design changes can also address certain cross-subsidies within customer classes in a relatively straightforward manner that also provides additional efficiency benefits. In principle, perfectly designed time- and location-varying pricing for all electric system components and externalities, applied identically to all customers, could eliminate the need for customer classes and cost allocation entirely while providing perfectly efficient price signals. This is unlikely to be the case for the foreseeable future but illustrates the conceptual point that an efficient improvement to rate design may be a strictly preferred option compared with the creation of a new rate class. For example, certain types of customers could be put on technology-neutral time-varying rates on an opt-out or mandatory basis, such as customers with storage, electric vehicles or distributed generation.

## 5.3 Load Research and Data Collection

Any cost of service study, as well as rate design, load forecasting, system planning and other utility functions, depends heavily on load research data. Cost allocation, in particular, requires reasonably accurate estimates for each class or group distinguished in the analysis, the number of customers, their energy usage (annual, monthly and sometimes more granular time periods), their kW demand at various times and under various conditions, and sometimes more technical measures such as **power factor**. The key principle is that there is diversity among customers in each class, meaning the consumption characteristics for the group are less erratic than those of any individual customer. Load research is the process of estimating that diversity.

At the very least, these data must be available by class across the entire system. For some applications, these data are useful and even essential at a more granular level, such as for each substation, feeder or even customer. Ideally, the cost of service study would be able to draw on information about the hourly energy usage by class, as well as the contribution of each class to the sum of the customer contributions to the maximum loads across the line transformers serving the

40 These factors may be offset by the utility's policy for charging new customers for extending the distribution system, as discussed in Section 11.2

class, the feeders serving the class, the substations serving the class and so on. Modern AMI and advanced distribution monitoring systems, if properly configured, can provide those data. Some utilities now routinely collect interval load data at each level of the system, while others are starting to acquire those capabilities.

The data needed for different cost allocation frameworks and methods can vary greatly, and it is difficult to generalize because of this. But at a high level, embedded cost techniques rely on one year of data or the equivalent forecast for one year. For many inputs, marginal cost techniques often rely on multiple years of data in order to estimate how costs are changing with respect to different factors over time. Different data may be needed for each step of the process, starting from the functionalization of costs down to the creation of **allocation factors**, or allocators, to split up the costs to customer classes.

Where the utility's metering and data collection do not directly provide comprehensive load data for all customers and system components, two options are available. The first and generally preferable option is sampling. Most investor-owned and larger consumer-owned utilities install **interval meters** specifically for load research purposes on a sample of customers in each class that does not have widespread interval metering.[41] The number and distribution of those meters should be determined to provide a representative mix of customer loads within the class (or other subgroups of interest) and to produce estimates of critical values (such as contribution to the monthly system peak load) that reach target levels of statistical significance.[42] These samples are typically a few hundred per class in order to meet the PURPA standard. Second, some smaller utilities borrow "proxy data" from a nearby utility with similar customer characteristics and more robust load research capabilities. Class load data are usually publicly available for regulated utilities. Neither sampled load nor proxy load will provide the precision of comprehensive interval metering, but they can provide reasonable estimates of the contribution of the group to demand at each hour, enabling development of cutting-edge techniques such as time-specific allocation methods.

Different elements of load research data are relevant in the creation of allocation factors for different parts of the system. For example:

- Most residential customers may be served through a transformer shared with other residential, commercial and street lighting customers, so the allocation of transformer costs to each class should ideally be derived from their contribution to the high-load periods of each such transformer.
- Some residential customers are served from feeders that peak in the morning and others from feeders that peak in midday or the evening; some of those feeders may reach their maximum load or stress in the summer and others in the winter. The sum of the class contribution to the various peak hours of the various feeders determines the share of peak-related costs allocated to the class for this portion of the distribution system.
- At the bulk power level, all customers share the generation and transmission system, and the diversity of all usage should be reflected, whether at the highest system hour of the year (a method known as 1 CP, for coincident peak), the highest hour of each month (12 CP) or the highest 200 hours of the year (200 CP), all **on-peak** hours, **midpeak** hours and off-peak hours, or any other criteria relevant for allocation.

Table 5 on the next page shows illustrative load research data for four customer classes. For the purposes of clear examples throughout the manual, we adopt the convention

41 Utilities usually have interval meters on customers over some consumption threshold for billing purposes. Smaller customers may have meters that record only total energy consumption over the billing period (typically a month), or both monthly energy and maximum hourly (or 15-minute) demand, neither of which provides any useful data for allocating time-dependent costs.

42 In 1979, FERC issued regulations to implement PURPA § 133 (16 U.S.C. § 2643), which requires the gathering of information on the cost of service. C.F.R. Title 18, Chapter 1, Subchapter K, Part 290.403(b) established the requirement, since repealed, that "the sampling method and procedures for collecting, processing, and analyzing the sample loads, taken together, shall be designed so as to provide reasonably accurate data consistent with available technology and equipment. An accuracy of plus or minus 10 percent at the 90 percent confidence level shall be used as a target for the measurement of group loads at the time of system and customer group peaks." See Federal Energy Regulatory Commission Order 48 (1979).

**Table 5. Illustrative load research data**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total | Used for |
|---|---|---|---|---|---|---|
| **Energy metrics (MWhs)** | | | | | | |
| Total | 1,000,000 | 1,000,000 | 1,000,000 | 100,000 | 3,100,000 | All energy-related costs, including generation, transmission, primary distribution |
| Total secondary | 1,000,000 | 1,000,000 | N/A | 100,000 | 2,100,000 | |
| Energy by time period | | | | | | |
| Summer | 600,000 | 650,000 | 500,000 | 30,000 | 1,780,000 | |
| Winter | 400,000 | 350,000 | 500,000 | 70,000 | 1,320,000 | |
| Daytime | 600,000 | 700,000 | 500,000 | 0 | 1,800,000 | |
| Off-peak | 400,000 | 350,000 | 500,000 | 90,000 | 1,340,000 | |
| Midpeak | 550,000 | 600,000 | 470,000 | 9,000 | 1,629,000 | |
| Critical peak | 50,000 | 50,000 | 30,000 | 1,000 | 131,000 | |
| **Customer metrics** | | | | | | |
| Line transformers used | 20,000 | 10,000 | N/A | 20,000 | 50,000 | Transformers, services |
| Customers | 100,000 | 20,000 | 2,000 | 50,000 | 172,000 | Billing |
| **Demand metrics (MWs)** | | | | | | |
| Sum of customer NCP | 2,000 | 1,000 | N/A | 100 | 3,100 | Input to line transformers |
| Class NCP: circuit | 400 | 400 | 250 | 100 | 1,150 | Primary distribution |
| Class NCP: substation | 300 | 300 | 225 | 100 | 925 | Substations |
| System 1 CP | 250 | 300 | 200 | 0 | 750 | Transmission, generation |
| System monthly 12 CP | 225 | 250 | 175 | 10 | 660 | |
| System 200 CP | 200 | 240 | 150 | 10 | 600 | |

of a commercial customer class of all general service customers served at secondary voltage, labeled as "Secondary commercial," and an industrial customer class of all general service customers served at primary voltage, labeled as "Primary industrial."

In this illustration, the sum of individual customer noncoincident peak demands is 3,100 MWs, excluding the primary industrial class that is not shown in the table.[43] However, the coincident peak demand served by the utility becomes more diverse as we move up the system, a phenomenon described in more detail in Section 5.1. As a result, the observed coincident peak demands are lower at more broadly shared portions of the system. At the highest level, this illustrative system has a 750-MW coincident peak demand for the highest single hour, labeled as "System 1 CP." In between, the sum of the class NCPs at the circuit level, labeled as "Class NCP: circuit," is 1,150 MWs, and the sum of the class NCPs at the substation level, labeled as "Class NCP: substation," is 925 MWs. Customers served at primary voltage (primary industrial) have no utility-provided line transformers, and the first level at which their demand is typically relevant is the circuit level.

The street lighting class is important to note with respect to the volatility of results. Because this class has zero daytime usage and a very different (typically completely stable overnight) load profile than other classes, it is highly affected by the choice between noncoincident methods and either coincident or hourly methods. In addition, because streetlights represent many points of delivery but are typically located only in places where other customers are nearby, this class almost never "causes" the installation of a transformer or the creation of a secondary delivery point but also does account for a huge number of the individual points of use

43 In Table 5, the sum of customer NCPs for the primary industrial class is shown as "N/A" because these customers do not use line transformers and thus this demand metric is not generally relevant to this class. For more general purposes, we are assuming that the sum of customer NCPs for the primary industrial class in this illustration is 300 MWs, bringing the overall total to 3,400 MWs.

**Table 6. Simple allocation factors derived from illustrative load research data**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Used for |
|---|---|---|---|---|---|
| **Energy metrics (MWhs)** | | | | | |
| Total | 32% | 32% | 32% | 3% | All energy-related costs, including generation, transmission, distribution |
| Total secondary | 48% | 48% | N/A | 5% | |
| Energy by time period | | | | | |
| Summer | 34% | 37% | 28% | 2% | |
| Winter | 30% | 27% | 38% | 5% | |
| Daytime | 33% | 39% | 28% | 0% | |
| Off-peak | 30% | 26% | 37% | 7% | |
| Midpeak | 34% | 37% | 29% | 1% | |
| Critical peak | 38% | 38% | 23% | 1% | |
| **Customer metrics** | | | | | |
| Line transformers used | 40% | 20% | N/A | 40% | Transformers, services |
| Customers | 79% | 17% | 3% | 1% | Billing |
| **Demand metrics (MWs)** | | | | | |
| Sum of customer NCP | 65% | 32% | N/A | 3% | Input to line transformers |
| Class NCP: circuit | 35% | 35% | 22% | 9% | Primary distribution (legacy) |
| Class NCP: substation | 32% | 32% | 24% | 11% | Substations |
| System 1 CP | 33% | 40% | 27% | 0% | Transmission, generation |
| System monthly 12 CP | 34% | 38% | 27% | 2% | |
| System 200 CP | 33% | 40% | 25% | 2% | |

Note: Class percentages may not add up to 100 because of rounding.

on the system. Put another way, we all like streetlights near our homes and businesses, but nearly all of them go in as a secondary effect of residential or commercial development; a few are along major highways without a nearby residence or business, but these are rare.

The next step is generating allocation factors to be used in the allocation phase of the cost study. For embedded cost studies, these are applied to the total investment and expense by FERC account, while in marginal cost studies they are applied to the calculated unit costs for each type of system component.

Table 6 shows the data above converted to allocation factors. The only implicit assumption is that the circuit-level peak demand for the residential class is one-fourth of the customer NCP demand due to load diversity and that for the commercial class it is one-half, reflecting lower diversity of commercial customer usage across the day compared with residential load. The raw factors are computed simply by dividing each class contribution to each category by the system total, then converting to percentages. For embedded cost of service studies, this manual recommends the use of class hourly energy use as a common allocation factor for all shared system components in generation, transmission and distribution where the system is made up of components essential for service at any hour, but sized for maximum levels of usage, and where the class contribution to that usage varies. The only one of these factors that is not self-explanatory is the midpeak factor, which takes both on-peak and **critical peak** usage into account, reflecting class usage in all higher-cost hours. This is illustrative of the probability-of-dispatch method, in which the likelihood of any resource being dispatched at specified hours is measured. There is no diversity of street lighting usage in this example, but little or no demand imposed at the system peak hours. Customer weighting factors are typically based on the relative cost of meters and billing services for different types of customers, based on complexity.

**Table 7. Composite allocation factors derived from illustrative load research data**

| Method | Components | Residential | Secondary commercial | Primary industrial | Street lighting | Used for |
|---|---|---|---|---|---|---|
| **Equivalent peaker** | 20% system 200 CP/ 80% energy | 32% | 34% | 31% | 3% | Generation, transmission |
| **On-peak** | 50% midpeak/ 50% critical peak | 36% | 38% | 26% | 1% | Peaking generation |
| **Average and peak** | 50% class NCP/ 50% energy | 34% | 34% | 27% | 6% | Primary distribution |
| **Minimum system** | 50% customer/ 50% class NCP: circuit | 57% | 26% | 12% | 5% | Circuits (legacy) |
| **Equivalent peaker for transformers** | 20% delivery points/ 80% customer NCP | 60% | 30% | 0% | 11% | Line transformers and secondary service lines |

Note: Class percentages may not add up to 100 because of rounding.

In Table 6, we have calculated allocation factors shown as a class percentage of each usage metric. In Part II, we discuss in what circumstances each of these will be appropriate for embedded cost of service studies. In many cases, weighted combinations of these are appropriate. Several commonly used composite allocation factors are shown in Table 7, computed by weighting values in Table 6.

Given the wide diversity of utilities and their load patterns, readers should be careful about overgeneralizing from these illustrative examples. However, some patterns will hold true across the board. For example, the minimum system method will always allocate more costs to classes with large numbers of customers, at least compared with the basic customer method.

# 6. Basic Frameworks for Cost Allocation

We group cost allocation studies into two primary families. Embedded cost studies look at existing costs making up the existing revenue requirement. Marginal cost studies look at changes in cost that will be driven by changes in customer requirements over a reasonable planning period of perhaps five to 20 years. In the same family as marginal cost studies, total service long-run incremental cost (TSLRIC) studies look at the cost of creating a new system to provide today's needs using today's technologies, optimized to today's needs. Each has a relevant role in determining the optimal allocation of costs, and regulators may want to consider more than one type of study when making allocation decisions for major utilities that affect millions of consumers.

## 6.1 Embedded Cost of Service Studies

Embedded cost of service studies may be the most common form of utility cost allocation study, often termed "fully allocated cost of service studies." Most state regulators require them, and nearly all self-regulated utilities rely on embedded cost of service studies. The distinctive feature of these studies is that they are focused on the cost of service and usage patterns in a test year, typically either immediately before the filing of the rate case or the future year that begins when new rates are scheduled to take effect. This means there is very little that accounts for changes over time, so it is primarily a static snapshot approach. Embedded cost of service studies are also closely linked to the revenue requirement approved in a rate case, which can be administratively convenient.

Generally speaking, in the traditional model displayed in Figure 18 on the next page, functionalization identifies the purpose served by each cost (or the underlying equipment or activity), classification identifies the general category of factors that drive the need for the cost, and allocation selects the parameter to be used in allocating the cost among classes.[44]

Although they are convenient parts of organizing a cost of service study, functionalization and classification decisions are not necessarily critical to the final class cost allocations. The cost of service study can get to the same final allocation in several ways. For example, consider the reality that a portion of transmission costs is driven by the need to interconnect remote generation to avoid fuel costs. This can be reflected by functionalizing a portion of transmission cost as generation, or by classifying a portion of transmission in the same manner as the remote generation, or it can be recognized by using a systemwide transmission allocator with some energy component. In either case, a portion of costs is allocated based on energy throughput, not solely on design capacity or actual capacity utilization.

### 6.1.1 Functionalization

In this first step, cost of service studies divide the utility's accounting costs into a handful of top-level functions that mirror the elements of the electric system. At a minimum, this includes three functions:[45]

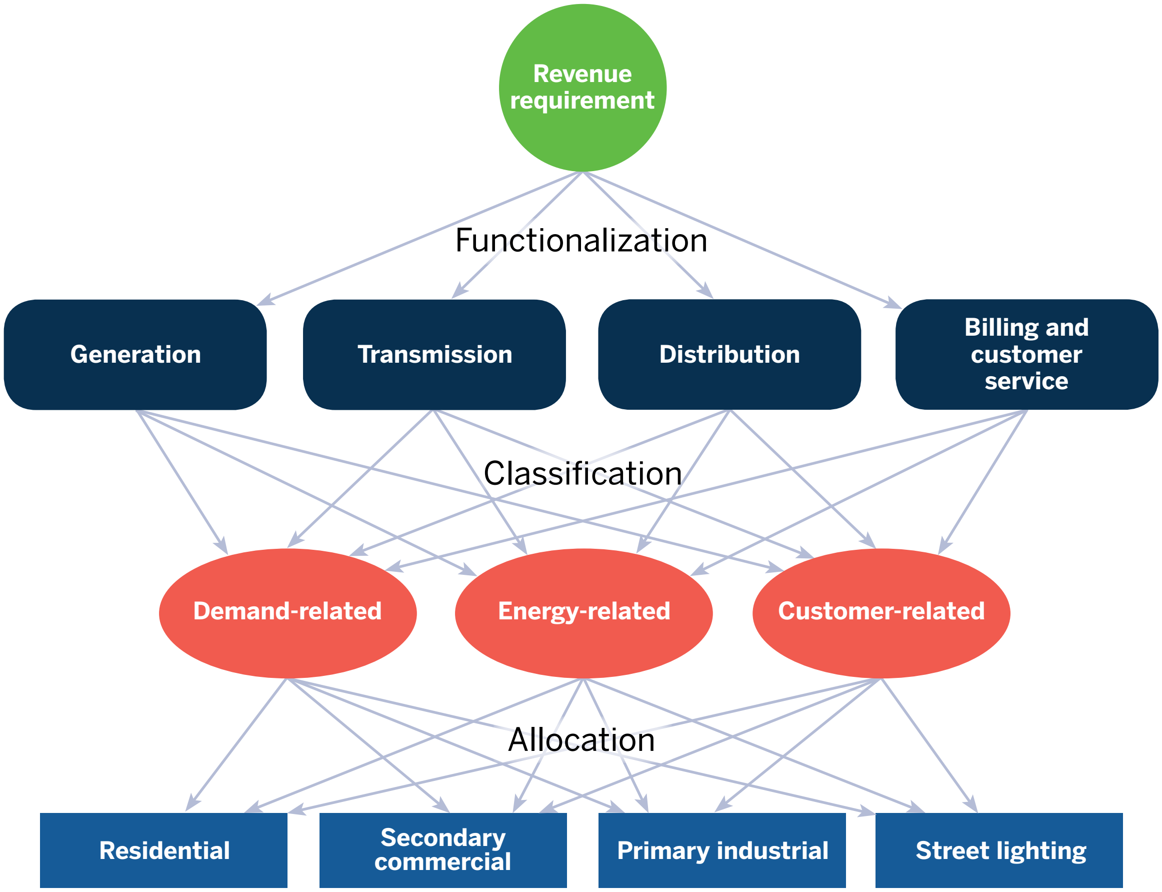
- Generation:[46] the power plants and supporting equipment, such as fuel supply and interconnections, as well as purchased power.
- Transmission: high-voltage lines (which may range from 50 kV to over 300 kV) and the substations connecting

44 The third step is usually called allocation, which is the same as the name of the entire process. This step involves the selection or development of allocation factors. Some analysts refer to this third step as factor allocation to prevent confusion.

45 Some of the costs, such as for energy efficiency programs and advanced meters, may serve multiple functions and must be assigned among those functions or treated as special functional categories.

46 Some sources use the term "production" instead. This manual uses the term "generation" and generally includes exports from storage facilities under this category.

**Figure 18. Traditional embedded cost of service study flowchart**




those lines, moving bulk power from generation to the distribution system.

- Distribution: lower-voltage primary feeders (in older systems, 4 kV and 8 kV; in newer areas, typically 13 kV to 34 kV) that run for many miles, mostly along roadways, and the distribution substations that step power down to distribution voltages; line transformers that step the primary voltages down to secondary voltages (mostly 120 V and 240 V); and the secondary lines that connect the transformers to some customers' service drops.

Although some utility analysts combine all costs into these three functions, the better practice is to include other functions as well at this stage:

- Billing and customer service: Also known as retail service or erroneously labeled entirely as customer-related costs, these are directly related to connecting customers (service drops, traditional meters) and interacting with them (meter reading, billing, communicating).
- General plant and administrative and general expenses: Overhead investments and expenses that jointly serve multiple functions (e.g., administration, financial, legal services, procurement, public relations, human resources, regulatory, information technology, and office buildings and equipment) can be kept separate at this stage. In some circumstances, these costs could be attributed to certain functions but are not tracked that way in a utility's system of accounts.
- Public policy program costs: In many jurisdictions, these costs are administered and allocated through another process; but if handled in a rate case, energy efficiency and other public policy programs should be tracked separately.

Historically, in most cases functionalization decisions can follow the utility's accounting and are noncontroversial.

The investment that is booked as generation units is usually part of the generation function. But there are exceptions. In some situations, the function of an investment may not match the accounting category. Examples include the following:

- Transmission lines and substations that are dedicated to connecting specific generating plants to the bulk transmission network. These assets are often in the accounting records as transmission but are more properly functionalized as generation.
- Substations that contain switching equipment to connect transmission lines of the same voltage to one another, high-voltage transformers that connect transmission lines of different voltages, and lower-voltage transformers that connect transmission to distribution. These facilities may be carried in the accounting records as entirely transmission or entirely distribution but are properly split between transmission and distribution in the functionalization process.
- Equipment within transmission substations that look like distribution equipment (e.g., poles, line transformers, secondary conductors, lighting). These might be booked in distribution accounts but are functionally part of the transmission substation.

In addition, many cost of service studies subfunctionalize some costs within a function, such as the following:

*Generation*

- Differentiating baseload generation (which runs whenever it is available or nearly so), intermediate generation (which typically runs several hours daily) and **peaking generation** (which runs only in a few high-load hours and when other generation is unavailable).
- Separating generators by technology to recognize such factors as renewable resources procured to meet energy-based environmental goals, the differing reliability contributions per installed kW of various technologies (e.g., wind, solar, thermal) and the differences in cost structure and output pattern between thermal, wind, solar and hydro resources.

*Transmission*

- Categorizing lines (and associated substations) by their role in operations, such as networking together the utility's service territory, providing radial supply to scattered distribution substations or importing low-cost baseload energy from distant suppliers.
- Segregating lower-voltage subtransmission facilities (typically under 100 kV) from higher-voltage facilities.
- Treating interconnections differently from the internal transmission network.
- Separating substations from lines.

*Distribution*

- Separating substations, lines (comprising overhead poles, underground conduit and the wires) and line transformers.
- Segregating costs of system monitoring, control and optimization related to reducing losses, improving **power quality** and integrating distributed renewables and storage.
- Dividing lines into primary and secondary components.
- In some cases, separating underground from overhead lines.

*Billing and customer service*

- Subfunctionalizing meters, services, meter reading, billing, customer service and other components, each of which may be allocated separately.
- Separating meters by technology — traditional kWh meters, **demand meters**, remotely read meters and advanced meters with hourly load recording and other capabilities — with different costs and different functions (including, for the advanced meters, services to the entire system).

*General plant and administrative and general expenses*

- Subfunctionalizing by type of cost: pensions and benefits, property insurance, legal, regulatory, administration, buildings, office equipment and so on.

In the future, organizing costs by function probably will still be helpful in organizing thinking about cost causation, but the cost of service study may need to differentiate functions in new ways. For example, distributed generation, storage, energy efficiency, demand response and smart grid technologies can provide services that span generation, transmission and distribution.

## 6.1.2 Classification

The second step of the process classifies each function or subfunction (i.e., each type of plant and expense) as being caused by one or more categories of factors. In particular, most cost of service studies use the classification categories of demand (meaning some measure of loads in peak hours or other hours that contribute to stressing system reliability or increasing capacity requirements on the generation, transmission or distribution systems), energy and customer number, and some use other categories (e.g., direct assignment, such as of street lighting).

The classification of most costs as demand-, energy- or customer-related dates back many decades. These categories can still be used but need to be interpreted more carefully as the utility system has changed in many ways:

- Utility planning has become more sophisticated.
- Utilities have access to more granular and comprehensive data on load and equipment condition.
- The variety of generation resources has increased to include wind, solar and other renewables with performance characteristics very different from legacy thermal and hydro resources.
- Multiple storage technologies are affecting generation, transmission and distribution costs.
- Legacy hydro, nuclear and fossil resources continue to operate and provide benefits to the utility system, but new similar resources and even continued operation of some existing units may no longer be cost-effective. Until they are retired, all or a portion of costs will remain in the allocation study.
- Demand response programs have increased in scale, role and variety.
- Utility spending on energy efficiency programs has increased.
- Advanced metering technology has added system benefits to a traditionally customer-related asset.

The demand and energy classifications are often treated as totally separate but, as discussed in Chapter 5, the load in many hours contributes to needs that have traditionally been classified to demand, and some hours are more important than others in driving energy costs. With improved information about class loads, and with a range of new technologies, it may be appropriate to move past the traditional energy and demand classifications and create new more granular distinctions, as discussed further in Chapter 17.

**Table 8. 1992 NARUC cost allocation manual classification**

| Cost function | Typical cost classification |
|---|---|
| **Production** | Demand-related<br>Energy-related |
| **Transmission** | Demand-related<br>Energy-related |
| **Distribution** | Demand-related<br>Energy-related<br>Customer-related |
| **Customer service** | Customer-related<br>Demand-related |

Source: National Association of Regulatory Utility Commissioners. (1992). *Electric Utility Cost Allocation Manual*

Table 8 reproduces a table from the 1992 NARUC *Electric Utility Cost Allocation Manual*, showing how the classification step worked in that period (p. 21).

This was a simplification even at the time, and changes to the industry and in the available data and analytical techniques merit reevaluation and reform. For example, a legacy framework for variable renewable capacity, particularly wind and solar, could treat the investment for utility-owned resources as 100% demand-related, since there are no variable fuel costs. However, power purchase agreements for these same resources are typically priced on a per-kWh basis from independent power producers. This could lead to two different approaches for the same asset depending on the ownership model, an obvious error in analysis that should be avoided by considering the actual products and services being provided. In addition, most of the benefits of wind and solar do not necessarily accrue at peak hours — the underlying justification of a demand-related classification. Similarly, analog meters were only useful for measuring customer usage and billing, but new AMI provides data that can be used for system planning and provides new opportunities for energy management and peak load reduction.

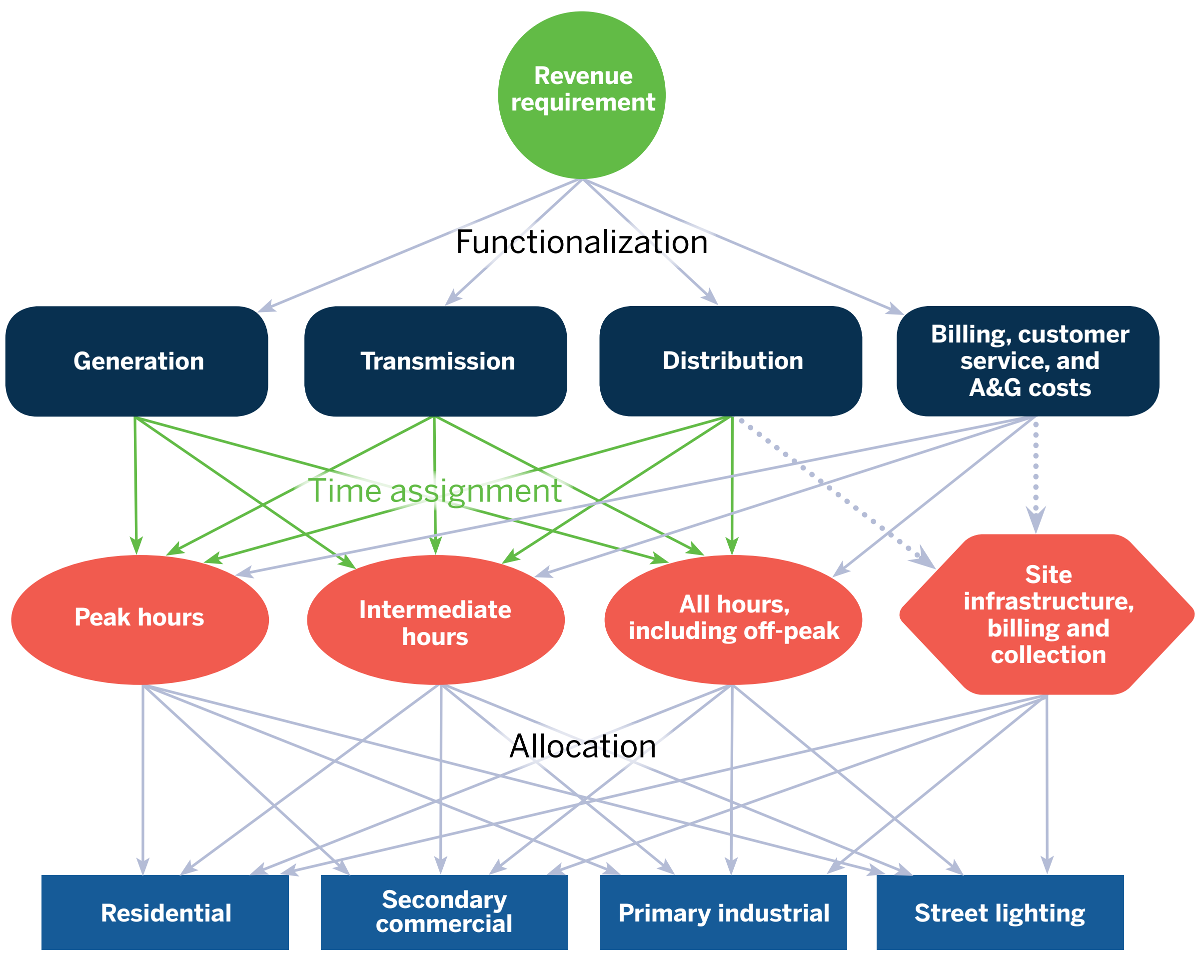
### 6.1.3 Allocation

The final step of the standard allocation process is the application of an allocation factor, or allocator, to each cost category.[47] An allocator is a percentage breakdown of the selected cost driver among classes. Within each broad type of classification, utilities use multiple allocators for various cost categories. For example, many different measures of "demand" are used to allocate demand-related costs, including various measures of contribution to coincident peaks (a single annual system coincident peak, or 1 CP); the average of several high-load monthly coincident peaks (e.g., 3 CP or 4 CP); the average of all 12 monthly coincident peak contributions (12 CP); the average of class contribution to some number of high-load hours (e.g., 200 CP); or different measurements of class maximum load (class noncoincident peak) at any time during the year. Usage of these peak-based demand allocators is often referred to as the **peak responsibility method**.

Generation allocators are sometimes differentiated among resources, to reflect the usage of different types of capacity and to retain the benefit of legacy resources for historic loads. Customer allocators are often weighted by the average cost of providing the service to customers in the various classes so that the cost of customer relations, for example, may be allocated with a weight of 1 for residential customers, 2 for small commercial, 5 for medium commercial and 20 for industrial.

Other costs, such as A&G expenses, are sometimes allocated on the basis of a labor allocator where the classification and allocation of underlying labor costs for the

**Figure 19. Modern embedded cost of service study flowchart**




47 Note that "allocation" is the term normally used for the entire process of assigning revenue requirements to classes and is also the term used for the last step of that process.

system is used for a set of other purposes. This is sometimes referred to as an internal allocator because it comes internally from previous calculations in the process. This is in contrast with "external allocators" based on facts and calculations outside of the cost allocation process, such as system peak and energy usage. Lastly, a variety of costs may be allocated based on a revenue allocator, which is based on the division of costs across all the classes.

### 6.1.4 Potential for Reform

As hourly data become available for all parts of the system, from transmission lines and substations through distribution feeders and line transformers to individual customers, an additional approach to classification and allocation becomes feasible: assigning costs directly to the time periods or operating conditions in which they are **used and useful**. This approach may entirely bypass the traditional classification step, at least between energy and demand.[48] Some relatively recent approaches recognize the complexity of cost drivers and combine classification and allocation into time-varying direct assignment of costs, as explained in Part II.

These time-varying allocation methods are discussed in Chapter 17 and Section 9.2; Figure 19 shows a simplified version.

Table 9 shows a simplified allocation study (very few cost categories and only two customer classes) and a caricature of the effect of using very different approaches. Both are embedded cost studies, but they produce dramatically different results.

The first study uses what might have passed for a reasonable cost allocation method a few decades ago, with all generation capacity and transmission costs allocated

**Table 9. Results of two illustrative embedded cost of service study approaches**

| | | Legacy study: Peak responsibility/minimum system | | | Modern study: Base-peak/basic customer | | |
|---|---|---|---|---|---|---|---|
| Cost category | Revenue requirement | Allocation method | Residential | Commercial and industrial | Allocation method | Residential | Commercial and industrial |
| **Generation** | | | | | | | |
| Baseload | $100,000,000 | Peak demand (1 CP) | $60,000,000 | $40,000,000 | All energy | $50,000,000 | $50,000,000 |
| Peaking | $50,000,000 | Peak demand (1 CP) | $30,000,000 | $20,000,000 | On-peak energy | $27,500,000 | $22,500,000 |
| Fuel | $100,000,000 | All energy | $50,000,000 | $50,000,000 | All energy | $50,000,000 | $50,000,000 |
| Subtotal | | | $140,000,000 | $110,000,000 | | $127,500,000 | $122,500,000 |
| **Transmission** | $20,000,000 | Peak demand (1 CP) | $12,000,000 | $8,000,000 | 75% all energy/ 25% on-peak energy | $10,300,000 | $9,800,000 |
| **Distribution** | | | | | | | |
| Circuits | $50,000,000 | 50% peak demand/ 50% customer | $37,500,000 | $12,500,000 | 75% all energy/ 25% on-peak energy | $25,600,000 | $24,400,000 |
| Transformers | $20,000,000 | Customer | $18,000,000 | $2,000,000 | 75% all energy/ 25% on-peak energy | $10,300,000 | $9,800,000 |
| Advanced meters | $10,000,000 | Customer | $9,000,000 | $1,000,000 | 50% customer/ 25% all energy/ 25% on-peak energy | $7,100,000 | $2,900,000 |
| Subtotal | | | $64,500,000 | $15,500,000 | | $43,000,000 | $37,000,000 |
| **Billing and collection** | $20,000,000 | Customer | $18,000,000 | $2,000,000 | Customer | $18,000,000 | $2,000,000 |
| **Total** | $370,000,000 | | $234,500,000 | $135,500,000 | | $198,750,000 | $171,250,000 |
| **Average per kWh** | $0.123 | | $0.156 | $0.09 | | $0.133 | $0.114 |
| **Difference** | | | | | | **-15%** | **+26%** |

Note: Numbers may not add up to total because of rounding.

48 Some costs associated with providing service under rare combinations of load and operating contingencies may not fit well into this framework.

Table 10. Illustrative allocation factors

| Method | Residential | Commercial and industrial |
|---|---|---|
| **Peak demand (1 CP)** | 60% | 40% |
| **All energy** | 50% | 50% |
| **On-peak energy** | 55% | 45% |
| **Customer** | 90% | 10% |
| **50% peak demand (1 CP)/ 50% customer** | 75% | 25% |
| **75% all energy/ 25% on-peak energy** | 51.3% | 48.8% |
| **50% customer/ 25% all energy/ 25% on-peak energy** | 71.3% | 28.8% |

on the highest-hour peak demand and most distribution costs allocated based on customer count. The second uses a simple time-based assignment method, in which all costs are allocated to usage in the hours for which the costs are incurred. This method recognizes that costs have a base level needed to provide service at all hours and incremental costs to provide service at peak hours. It also recognizes the multiple purposes for which advanced meter investments are made. The results are quite striking, with the second study showing a residential class revenue requirement 15% lower than the first. This set of assumptions probably forms the bookends between which most well-developed embedded cost studies would fall.

The first approach presents a legacy method that some industrial and large commercial customer representatives still sometimes propose. The second is a method that residential consumer advocates often champion. This change in method drives a significant change in the result. Both of these are "cost of service" results.

The point of these illustrative examples is not to suggest a specific approach, nor to defend any of the individual allocation methods shown, but to illustrate how different classification and allocation assumptions affect study results. Simply stating that a proposed cost assignment between classes is "based on the cost of service" may ignore the very important judgments that goes into the assumptions of the study. Table 10 shows the illustrative allocators that drive the results in Table 9.

Figure 20 on the next page shows a Sankey diagram for the legacy embedded cost of service study shown in Table 9. In that legacy study, most costs are classified as demand-related, and 60% of demand-related costs get allocated to the residential class. Similarly, a significant amount of costs are classified as customer-related, which are then overwhelmingly allocated to the residential class. This is because the **minimum system method** classifies all metering, billing and line transformers as customer-related, along with a portion of the distribution system.

In contrast, Figure 21 on Page 77 shows a Sankey diagram for the modern study in Table 9. More than half of peak hours costs are allocated to the residential class, but the peak hours classification is much less significant than the demand-related classification in the legacy study. Similarly, the basic customer method classifies only billing and a portion of advanced metering costs as customer-related. These costs are still primarily allocated to the residential class, but the aggregated differential nevertheless comes out significantly lower than in the legacy study. The remainder of advanced metering costs is split between all energy and on-peak energy because the purpose of these investments is to reduce energy costs and peak capacity requirements.

Figure 20. Sankey diagram for legacy embedded cost of service study

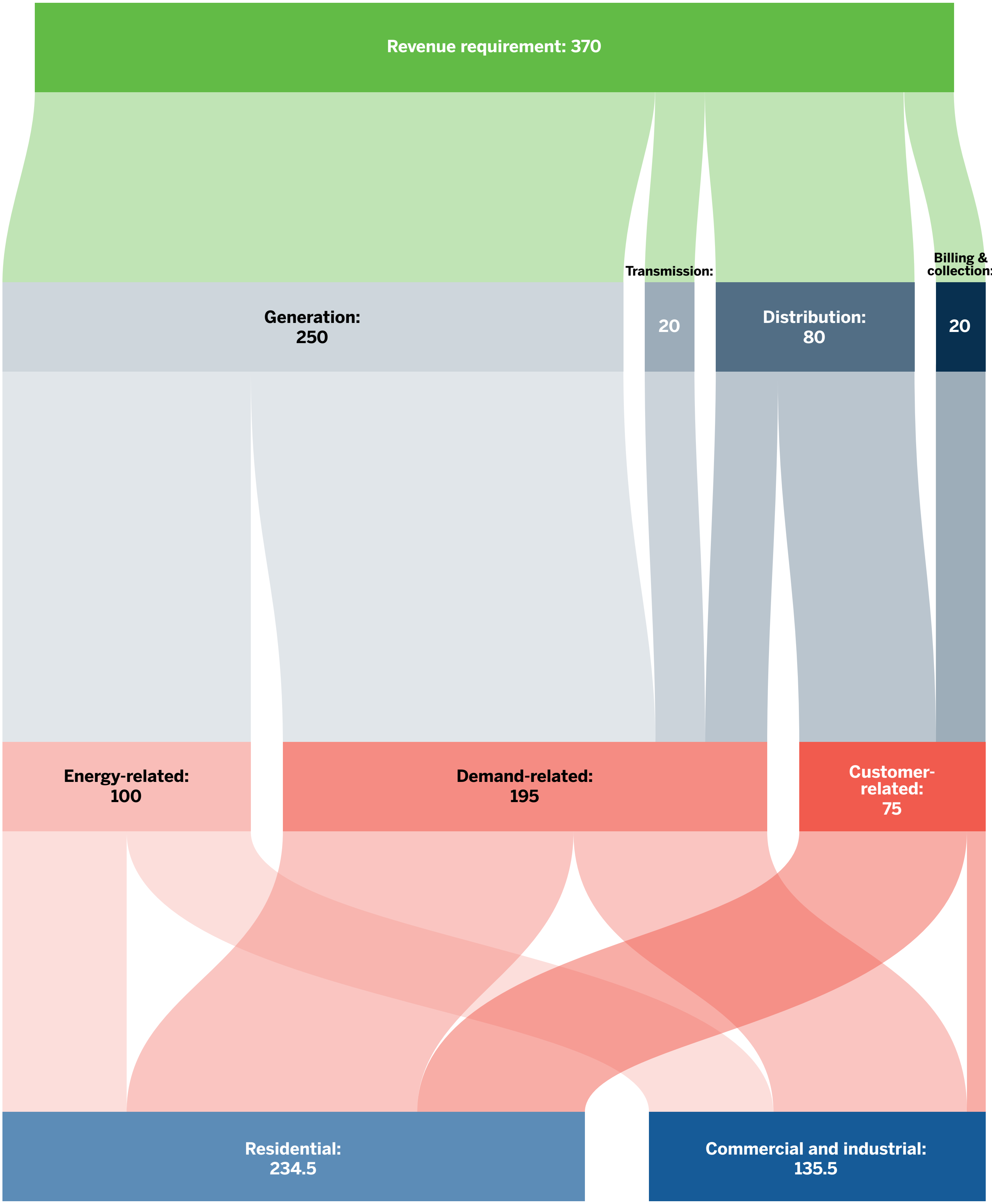
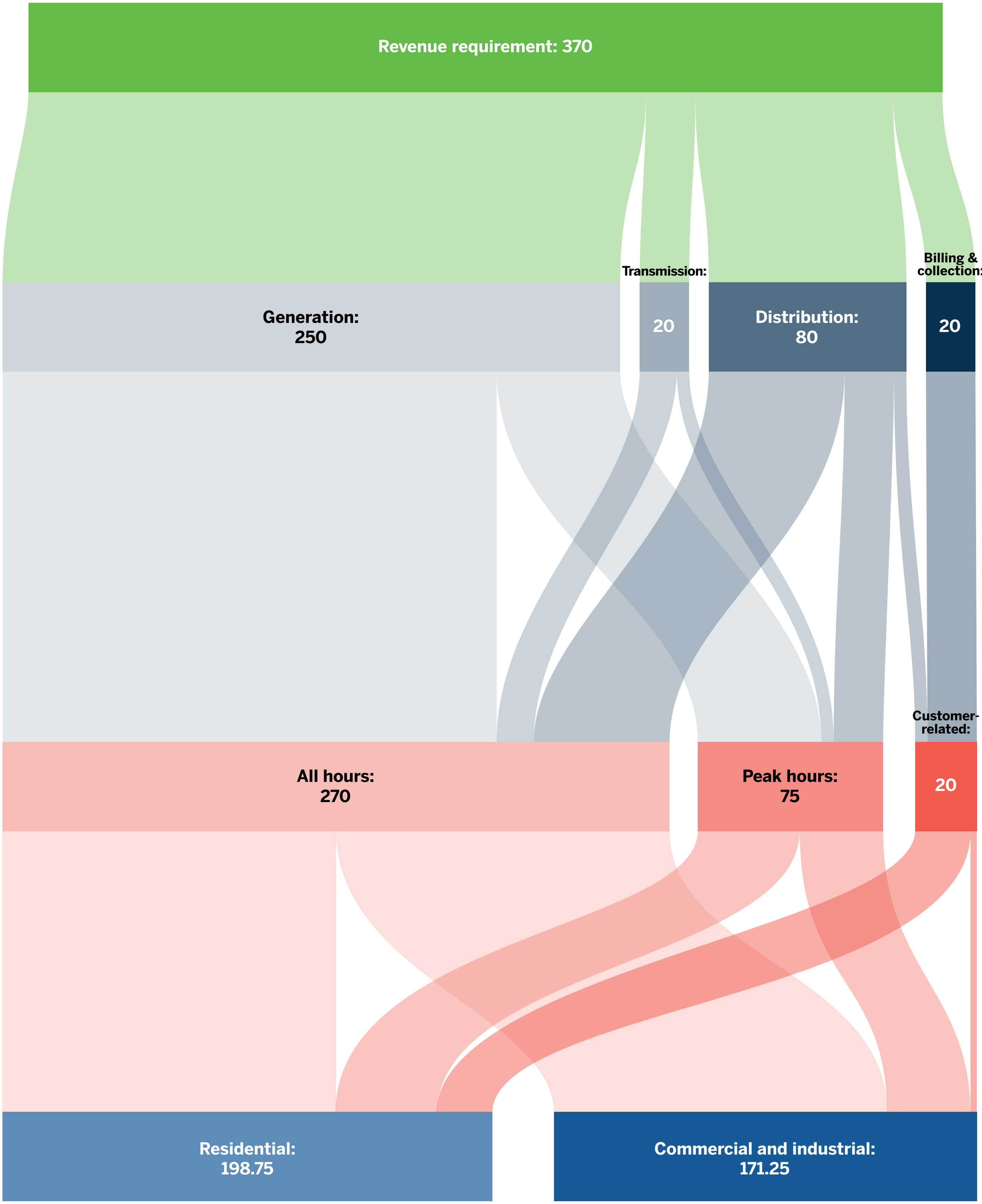


Figure 21. Sankey diagram for modern embedded cost of service study



## "Fixed" versus "variable" costs

In the past, some cost allocation studies have relied on a simplified model of cost causation, in which certain costs are labeled as variable and then classified as energy-related and apportioned among classes based on class kWh usage. The remaining costs, labeled as fixed, are classified as demand-related or customer-related and allocated on some measure of peak demand or customer number, respectively.[49] This antiquated approach is based on fundamental misconceptions regarding cost causation. But it still underlies many arguments about cost allocation, perhaps because it typically works to the benefit of customer classes with high load factors and small numbers of customers — which describes most utilities' large industrial classes, data centers and even supermarkets.[50] This technique ignores the reality that modern electric systems trade off capital, labor, contractual obligations, fuel and other expenditures to minimize costs.

One of the problems with using the fixed/variable dichotomy to classify costs is the ambiguity of the concept of a cost being "fixed." Nearly all observers agree that certain generation costs are variable because they are short-term marginal costs that vary directly with usage patterns. These costs include:

- Fuel purchasing and disposal costs.[51]
- Variable operating costs related to consumables (e.g., water, limestone, activated carbon, ammonia) injected to increase output, reduce emissions or provide cooling to the power plant as it produces energy.
- Allowances or offsets that must be purchased to emit various pollutants.
- Purchased power charges that depend on the amount of energy taken by the utility.[52]

Over the decades, nearly every other utility cost has been described as fixed in one context or another: capital, labor, materials and contract services. Most of these costs are fixed for the coming year, in the sense that they are committed (investments made, contracts signed, employees hired) and will not be immediately changed by usage levels (energy, demand or number of customers). However, almost all of these cost accounts are variable over a period of several years, and energy consumption may affect:

- Whether excess generation capacity or other redundant facilities can be retired or mothballed in order to reduce operating and capital expenditures or repurposed to increase the net benefits of the facility.
- Whether additional facilities are needed (increasing capital and operating costs).
- Whether contracts are extended.
- The cost of capacity that is built (e.g., combined cycle versus combustion turbine plants, larger T&D equipment to reduce losses).

As a result, these costs are not fixed over the planning horizon. From an economic perspective more generally, all costs vary in the long run.

Relatedly, nearly all competitive businesses and fee-charging public services recover their fixed costs based on units sold. Customers do not pay an access fee to enter a supermarket.

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49 In rate design, this approach has been extended to argue that all "fixed" costs must be recovered through **fixed charges**, often meaning customer and demand charges. These approaches promote neither equity nor efficiency.

50 Similarly, the fixed/variable approach is attractive to those who would justify rate designs with lower energy charges and higher customer and demand charges.

51 In previous decades, utilities would even argue that some fuel costs are fixed, on the grounds that having fuel on hand was necessary to allow the plant to function when required, or that a certain amount of fuel was required for startup, before any energy could be generated. These arguments appear to have largely disappeared, although similar issues are raised by the fuel security debate at FERC.

52 Many observers would add another category — expenses whose amount and timing vary with hours of operation, output or unit starts — even though not all cost of service studies separate those costs from other O&M expenses.

Restaurants, theaters and airlines have many costs that can be characterized as fixed (land, buildings, equipment, a large share of labor) and vary their unit prices by time of use but ultimately recover their capital investments and long-term costs from sales of output. RAP has done extensive analysis of utility distribution system investment and the relationship of that investment to the number of customers, peak demands and total kWhs. We found that these costs are roughly linear with respect to each of these metrics (Shirley, 2001).

Some version of the fixed/variable distinction may have been close to reality in the middle of the last century. Most utilities relied primarily on fossil steam plants, using newer, more efficient plants to serve baseloads and older plants to serve intermediate and peak loads. The capital costs of each were not very different. Fuel costs for oil, coal and natural gas were not very different. And because little was required in terms of emissions controls, coal plants were not much more expensive than other fossil-fueled plants.[53] By the 1970s, however, conditions had changed radically. Oil prices rose dramatically, new coal plants were required to reduce air emissions, and new generation technologies arose: nuclear, with high capital and O&M cost but low fuel prices; and combustion turbines, with low capital and O&M costs but high fuel costs. Utilities suddenly had a menu of options among generation technologies, including the potential for trading off short-term fuel costs for long-term capital investments. Today that menu has expanded even more and includes storage, demand response, price-responsive customer load and distributed generation.

As a result, the fixed/variable distinction has lost relevance and adherents over the last several decades. For example, many regulators classify capital investments using methods that recognize the contribution of energy requirements to the need for a wide variety of "fixed" costs for generation, transmission and distribution.[54]

53 In some areas, such as the U.S. Northwest, Manitoba and Québec, utilities had access to ample low-cost hydro facilities and mostly avoided construction of thermal generation.

54 These methods are discussed in chapters 9, 10 and 11.

## 6.2 Marginal Cost of Service Studies

The fundamental principle of marginal cost pricing is that economic efficiency is served when prices reflect current or future costs — that is, the true value today of the resources that are being used to serve demand — rather than historical embedded costs. Advocates for a marginal cost of service study approach work backward from this pricing concept to suggest that cost allocation should be based around marginal costs as well. Critics of marginal cost methods often point out that this economic theory is appropriate only when other conditions are present, including that all other goods are priced based on marginal costs, that there are no barriers to entry or exit from the market and that capital is fungible.

This is a very broad concept because it abstracts from and does not consider both theoretical and computational issues associated with the development of marginal costs. In contrast to the static snapshot that is typical of embedded cost approaches, marginal cost of service studies account for how costs change over time and which rate class characteristics are responsible for driving changes in cost. Importantly, marginal costs can be measured in the short run or long run. At one extreme, a true short-run marginal cost study will measure only a fraction of the cost of service, the portion that varies from hour to hour with usage assuming no changes in the capital stock. At the other, a total service long-run incremental cost study measures the cost of replacing today's power system with a new, optimally designed and sized system that uses the newest technology. In between is a range of alternatives, many of which have been used in states like Maine, New York, Montana, Oregon and California in determining revenue allocation among classes.

There is a strong theoretical link between optimal rate design and long-run marginal costs. Allocation based on marginal costs works backward from this premise; because pricing should be determined on this basis, cost allocation should as well. In its simplest form, a marginal cost study computes marginal costs for different elements of service, which can be estimated using a number of techniques, including proxies, regressions and other cost data. Table 11 shows illustrative marginal costs for different elements of the electric system.

Different marginal cost of service studies may base their costing on different elements of the system or different combinations. The categories of costs included in each element can also be more or less expansive. The estimated marginal costs are then multiplied by the billing determinants for each class. This produces a class marginal cost revenue requirement and, when combined with other classes, a system MCRR. However, revenue determination solely on this marginal cost basis will typically be greater or less than the allowed revenue requirement, which is normally computed on an embedded cost basis. It is only happenstance if marginal costs and embedded costs produce the same revenue or even similar levels of revenue. As a result, a marginal cost of service study must be adjusted to recover the correct annual amount from the revenue requirement.

Two notable long-run methods are discussed in this section: the long-run marginal cost approaches advocated by Lewis Perl and his colleagues at the consulting firm National Economic Research Associates (NERA) — now NERA Economic Consulting — and the total service long-run incremental cost approach.[55] In the 1980s, during the PURPA hearing era, many states considered and a few adopted the **NERA method** to measuring long-run marginal costs. California, Oregon, Montana and New York are examples of states that began relying on this approach to measuring marginal costs. This methodology generally looked at a 10-year or longer time horizon to measure what costs would change in response to changes in peak demand and energy requirements during different time periods and the number of customers served (National Economic Research Associates, 1977). One essential element of this was to define the cost of generation to meet peak period load growth (peaker units and associated T&D capacity) as much higher than the cost to meet off-peak load growth (increased utilization of existing assets). This approach was influenced by Alfred Kahn's theoretical focus on peak load costs and management (Kahn, 1970), and he himself was associated with NERA for many years.

For generation, one of the theoretical advances that made marginal cost of service studies attractive when they were first developed in the late 1970s was that generation costs were made up of capacity and energy costs, but the embedded plant was not classified to obtain these costs. Marginal energy costs were based on the incremental operating costs of the system (discussed in Chapter 18 in more detail), while capacity costs were the least cost of new capacity (at the time, typically a combustion turbine). The annualization for the capacity costs of all types is not based on the embedded rate of return but on a **real economic carrying charge** (RECC) rate that yields the same present value of revenue requirements when adjusted for inflation.

For transmission and distribution costs in the NERA method, the marginal costs have typically been estimated by determining marginal investment for new capacity over a number of historical and projected years and relating that investment to changes in some type of load or capacity measure in kWs. This relationship can be found either using regression equations (cumulative investment versus cumulative increase in load over the time period) or by simply dividing the number of dollars of investment by the total increase in load over the time period. O&M costs are generally based on some type of average over a number of historical and projected years, although obvious trends or anomalies can be taken into account.

**Table 11. Illustrative marginal cost results by element**

| | Units | Cost per unit |
|---|---|---|
| **Customer connection** | Dollars per year | $80 |
| **Secondary distribution** | Dollars per kW | $40 |
| **Primary distribution** | Dollars per kW | $80 |
| **Transmission** | Dollars per kW | $50 |
| **Generation capacity** | Dollars per kW | $100 |
| **Energy by time period** | | |
| On-peak | Dollars per kWh | $0.10 |
| Midpeak | Dollars per kWh | $0.07 |
| Off-peak | Dollars per kWh | $0.05 |

55 Short-run marginal cost approaches are actually much simpler, primarily varying fuel consumption and purchased power costs, but are applicable only in a limited number of circumstances.

For customer costs, the same type of arguments over classification between distribution demand and customer costs occur as in embedded cost studies. The marginal cost study needs data on the current costs of hooking up new customers by class. The method for annualizing the costs is in dispute (RECC versus a **new-customer-only method** that assigns the costs by new and replacement customers). O&M costs are again typically based on some type of average over historical and projected years.

The time horizon used for the NERA approach has proven controversial because it assumed the utility would install exactly the number of new customer connections and distribution lines required by new customers (i.e., all customer costs are "marginal") but would consider the adequacy of existing generation and transmission (which may be oversized to meet current needs) in determining the need for additional generation and transmission (meaning only some G&T costs are "marginal"). Many utilities have used a 10-year time horizon in this analysis, a period in which many found substantial excess capacity and, therefore, relatively low costs to meet increasing power supply needs. In addition, this methodology, as most often used, treats the cost of increased off-peak usage as only the fuel and variable power costs and losses associated with operating existing resources for additional hours, with no associated investment-related or maintenance-related cost, despite the reliance on expensive investments to produce that power.

The combination of these assumptions meant that many marginal cost of service studies over the last several decades would come to three basic conclusions:

- Power supply and transmission costs to meet off-peak loads were relatively low, due to available excess capacity.
- Power supply and transmission costs to meet peak load growth were higher.
- Distribution costs always grew in lockstep with the number of customers and distribution demands.

The most serious shortcoming of the NERA methodology is that if power supply is surplus due to imperfect forecasting, it assigns a very low cost to power; if it is scarce, the method assigns a very high cost. Neither of those circumstances is *caused* by the action of consumers in any class, but the presence of either can shift costs sharply among consumer classes. Because of this imbalanced result, regulators have adopted modifications to this methodology to equalize the time horizon for different elements of the cost of service. For example, not all customers will require new service drops and meters over a 10-year period — only new customers and those whose existing facilities fail. Some states apportion costs within functional categories, avoiding this problem and addressing markets with partial retail choice.

In contrast to the NERA approach and other marginal cost approaches, which start from the parameters and investments found in the existing system, the total service long-run incremental cost approach looks at a period long enough so that all costs truly are variable. This allows for an estimate of what the system would look like if it were completely constructed using today's technologies and today's costs. Today, new generation is often cheaper than existing resources, while the cost of transmission and distribution continues to rise.

The TSLRIC approach was developed in the context of regulatory reform for telecommunications (International Telecommunication Union, 2009). In the 1990s, as telecommunication technology advanced rapidly, incumbent local exchange companies (better known as phone companies) faced competition from new market entrants that did not have legacy system costs. These new competitors were able to offer service at lower cost than the local phone companies. Regulators did not want to discourage innovation but also did not want existing customers served by the local phone companies to suffer rate increases if select customers left the system.

The TSLRIC approach constructs a hypothetical system with optimal sizing of components, with neither excess capacity nor deficient capacity. It would use the most modern technology. In the context of an electric utility, it would likely rely on wind, solar and storage to a greater extent than most systems today, which would likely lead to lower costs. But it would also incur the cost of today's environmental and land use restrictions, such as the requirement for lower emissions from generation and undergrounding of transmission and distribution lines. These requirements have substantial societal benefits but can also drive up electric system costs.

One advantage of a TSLRIC study over a NERA-style study is that no class is advantaged or disadvantaged by a current surplus or deficiency of power supply or distribution network capacity, since costs for all classes would be based on an optimal mix of resources to serve today's needs. This is one of the most common critiques of the NERA methodology — that it favors any class that is served dominantly by the elements of a system that are in surplus.

## 6.3 Combining Frameworks

Several jurisdictions require both an embedded and a marginal cost of service study to support cost allocation and rate design. As a result, utilities and other parties may file several studies in the course of a rate proceeding. A regulator may reasonably use multiple cost studies in reaching decisions, using multiple results to define a range of reasonableness. Within that range, the regulator can apply judgment and all of the relevant non-cost concerns to determine the allocation of the revenue requirements among classes. Furthermore, the different types of studies provide different information that can be used at other stages in the rate-making process.

One approach is to use embedded cost methods to determine the allocation of the revenue requirement among customer classes and then a forward-looking cost method of some kind to design rates within classes. This applies the focus of embedded cost studies on equitably sharing the costs among classes while maximizing the efficiency of price signals in the actual rates that individual customers face in making consumption decisions that will affect future costs. The appropriate form of price signals can also be influenced by externalities that are not part of the embedded costs for a regulated utility. For example, many regulatory agencies that allocate costs among classes on embedded costs have reflected higher long-run marginal costs in adopting inclining block or time-of-use rates for customers with high levels of usage (either because large customers are better able to respond to price signals or because the larger customers have more expensive load shapes, such as for space conditioning).

In some situations, regulators will use one costing method to set rates for existing load while using a different method to set rates for new customers or incremental usage. Some jurisdictions have applied this technique for rate design within classes — as the foundation for most "economic development" rate discounts where marginal costs are lower than embedded costs, as well as for inclining block rates where marginal costs are higher than embedded costs. In addition, some jurisdictions have applied this technique across rate classes, allocating new incremental resources to specific rate classes. Depending on the trajectory of costs, this can have two different intended purposes:

- To provide a foundation upon which to impose on fast-growing classes the high costs of growth and to shelter slower-growing classes from these new costs.
- To provide a foundation to give the benefit of low-cost new resources to the growing class.

This approach to differential treatment of incremental resources may be applicable to situations where costs are being driven by disparate growth among customer classes. In the 1980s, for example, commercial loads in the U.S. grew much faster than residential loads, and this technique could be used to assign the cost of expensive new resources to the classes causing those new costs to be incurred.

## 6.4 Using Cost of Service Study Results

Quantitative cost of service study results should serve only as a guide to the allocation of revenue responsibility among classes, not as the sole determinant. Even the best cost of service study reflects many judgments, assumptions and inputs. Other reasonable judgments, assumptions and inputs would result in different cost allocations. Additionally, loads may be unstable, significantly changing class revenue responsibility between cost studies, particularly for traditional studies that base costs on single peak hours in one or several months. More globally, concepts of equity extend beyond the cost of service study's assignment of responsibility for causing costs or using the services provided by those costs to include relative ability to pay, gradualism in rate changes, differential risks by function and class and other policy considerations.

Chapter 27 addresses the many ways in which the results of cost of service studies can be used to guide regulators.

# 7. Key Issues for 21st Century Cost Allocation

Many important cost allocation issues for the current era are fundamentally different from those that existed when NARUC published its 1992 *Electric Utility Cost Allocation Manual*. This chapter sets forth the changes the industry has experienced and describes the approaches that may be needed to address those changes in cost allocation studies.

Inevitably, additional costing issues will emerge and require recognition in future cost of service studies. The fundamental considerations are why the costs were incurred and who currently benefits from the costs. Costs are often categorized using engineering and accounting perspectives that are useful for many applications but must not be allowed to obscure the fundamental questions of causation and benefits.

## 7.1 Changes to Technology and the Electric System

Technological change has affected every element of the electric system since the studies and decisions that informed the 1992 NARUC cost allocation manual. These changes include:

- Improved distribution system monitoring and advanced metering infrastructure, leading to new comprehensive data on the system and customers.
- Evolution of resource options to include significant amounts of variable renewables, new types of storage, energy efficiency and demand response.
- Significant commitments to DERs behind customer meters, including rooftop solar and storage.
- Beneficial electrification of transportation.
- Changes in fuel prices and the resource supply mix that have dramatically changed the operating pattern of various generation resources (addressed in more detail in Section 7.2).

These changes both enable and require new approaches in order to efficiently and equitably allocate costs across customer classes.

### 7.1.1 Distribution System Monitoring and Advanced Metering Infrastructure

In the past, customer meters were used solely to measure usage and render bills. Today, so-called smart meters are part of a complex web of assets that enable energy efficiency, peak load management and improved system reliability, in addition to the traditional measuring of usage and rendering of bills.

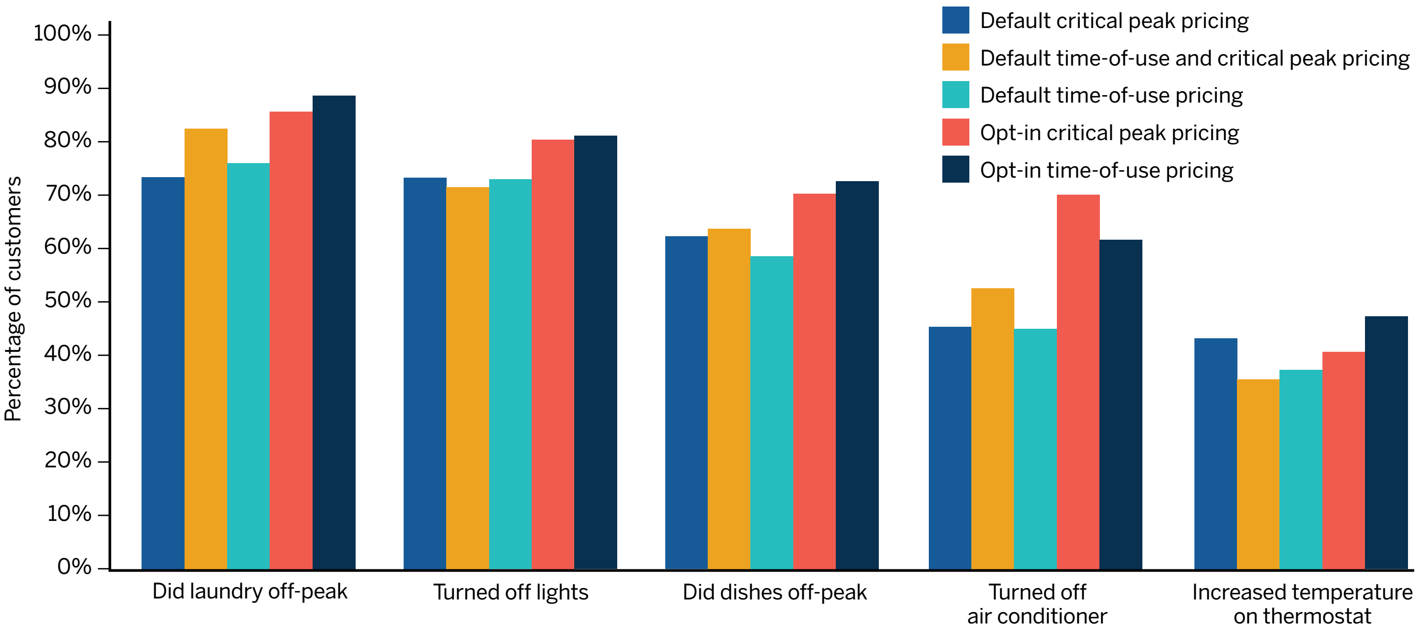
More recently, a number of utilities have used advanced meters to support demand response and other programs. Sacramento Municipal Utility District, for example, ran a pilot program to test the impacts of **dynamic pricing** and smart technology on peak load shaving and energy conservation. Figure 22 on the next page shows how customers in the program took steps to lower their electricity usage during high-load, higher-cost hours (Potter, George and Jimenez, 2014).

Smart meters (along with supporting data acquisition and data management hardware and software) can provide a number of services that improve reliability and reduce costs of generation, transmission and distribution.[56] Analysts have identified a wide range of expected and potential benefits. These include:

- Reduced line losses.
- Voltage control.
- Improved system planning and transformer sizing.
- The ability to implement rate designs that encourage energy efficiency.
- Reduced peak loads.
- Integration of EVs and renewables.

56 The broader concept of "smart grid" includes distribution (and sometimes transmission) automation devices such as automatic reclosers, voltage controls, switchable capacitors and sensors.

**Figure 22. Customer behavior in Sacramento Municipal Utility District pricing pilot**




Source: Potter, J., George, S., and Jimenez, L. (2014). *SmartPricing Options Final Evaluation*

- Operating savings from, among other things, reduced labor needs and improved outage management.

Lastly, smart meters, distribution sensors and modern computing power provide utilities with large amounts of data that can be used to determine the usage patterns of distribution and transmission equipment in great detail and support direct hourly allocation of costs.

## 7.1.2 Variable Renewables, Storage, Energy Efficiency and Demand Response

New variable renewable resources, such as wind and solar, are highly capital-intensive, and their contribution to system reliability varies greatly from region to region depending on when their generation occurs relative to peak demand.[57] The emergence of demand response as a service provides an opportunity to meet narrow periods of peak demand with relatively little capital investment by rewarding customers who curtail usage on request.

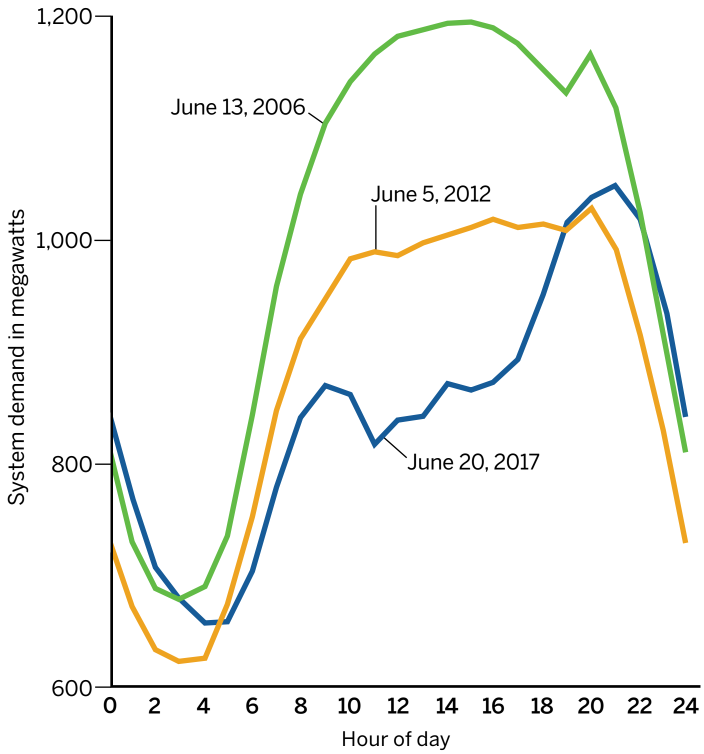
Investments in renewable resources, driven by policy and economic trends, can greatly change patterns in supply and demand that had been roughly constant for decades. Due to significant solar capacity in some regions, such as California and Hawaii, costs (e.g., extra **spinning reserves**, out-of-merit dispatch or quick-start generation) may also be incurred to rapidly ramp up other generation as solar output falls in the late afternoon, particularly if customer load does not drop dramatically from afternoon to evening.[58] Excess solar generation may create ramping costs, while storage resources may reduce ramping costs by both raising load at the beginning of the ramp period and trimming the peak toward the end of the ramp period.

In Hawaii, June load shapes changed as increased levels of distributed solar were added to the system. Figure 23 on the next page illustrates this, using data from the Federal Energy Regulatory Commission (n.d.). In 2006, the **system peak demand** was approximately 1,200 MWs at 1 to 3 p.m. By 2017, with extensive deployment of customer-sited solar, the peak demand was 1,068 MWs at 9 p.m. A cost allocation scheme must be adaptable enough to be relevant as significant changes in the shape and character of utility-served load take place.

57 Growth in solar resources, whether central or distributed, gradually reduces the reliability value of incremental solar capacity in many respects; the same is true for wind resources with respect to the reliability value of incremental wind and the equivalent for (if they become economically competitive) tidal and wave energy. In contrast, these different resources may be complementary to one another in certain respects.

58 The resulting load shape, first identified by Denholm, Margolis and Milford in 2008, is commonly known as a duck curve. See also Lazar (2016).

**Figure 23. Evolution of system load in Hawaii on typical June weekday**




Data source: Federal Energy Regulatory Commission. *Form No. 714 — Annual Balancing Authority Area and Planning Area Report*

The capacity role and treatment of variable renewable resources, such as wind and solar, vary among jurisdictions and RTOs. The cost of service study should reflect the role of these resources in supply planning, by classifying part of the renewable costs as demand-related and allocating those costs in proportion to class consumption in the hours contributing to capacity requirements. This should recognize that different types of variable renewable resources can be complementary in many respects as long as the temporal patterns, either daily or seasonal, are different. Even solar in slightly different regions can be complementary since they may not be affected in an identical way by cloud cover. For example, as shown in Figure 24 on the next page, a mix of wind resources from West and South Texas plus solar production combine to produce an overall resource shape that corresponds moderately well to the shape of the summer diurnal load (Slusarewicz and Cohan, 2018; Electric Reliability Council of Texas, 2019).

The costs of these resources can be assigned to the hours in which they generate energy, as discussed in Chapter 17. Determining the hours that variable resources provide energy (on either a historical or normalized forecast basis) is generally straightforward.

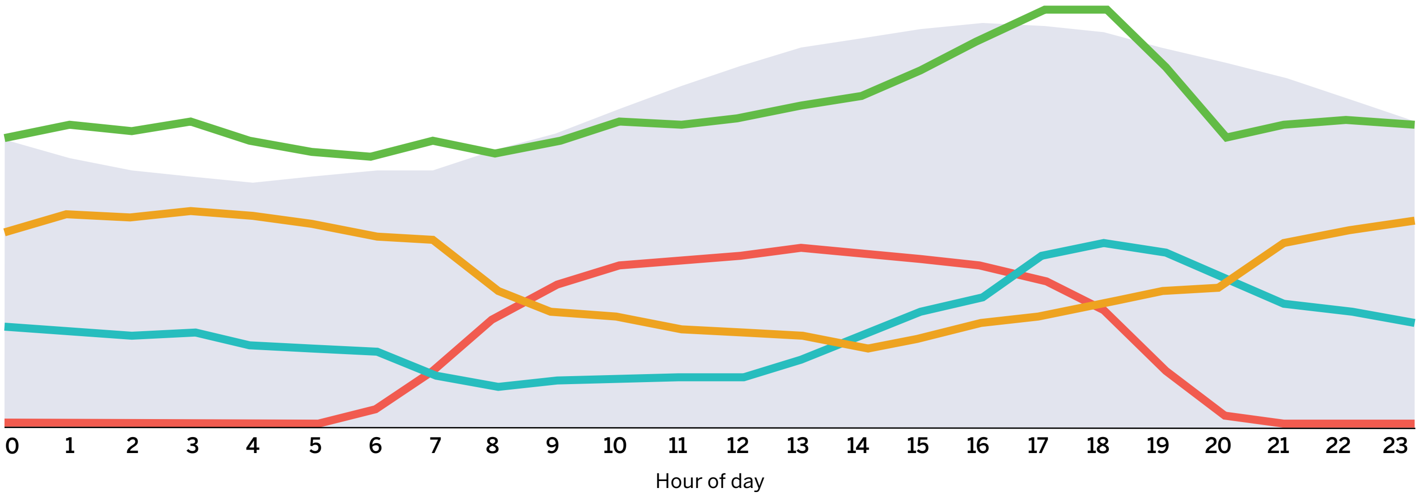
Distributed storage presents other issues and opportunities, as it is a capital-intensive peaking resource with no direct fuel costs, dependent on charging from other resources, and provides a variety of energy, capacity, transmission, distribution and **ancillary services** to the system and sometimes backup supply to host customers. Storage may displace T&D investments, reduce fuel consumption, enable renewable energy integration and provide emergency service at customer sites. Each of these functions has a different place in a modern cost allocation study.

A portfolio of energy efficiency measures reduces energy requirements, generation capacity requirements and stress on T&D equipment, as well as reduces customer billing determinants. As discussed in Section 14.1, energy efficiency expenditures can be classified and allocated in proportion to the benefits they produce. The plans and evaluation reports of the program administrator (the utility or a third party authorized to provide those services) generally provide sufficient data on the load shape and class distribution of load reductions. Since energy efficiency costs are recovered through a variety of mechanisms (rate based or expensed, through base rates or a discrete conservation surcharge or **rider**), the cost allocation should reflect the cost recovery method.

The costs of demand response programs — direct load control, customer load automation (e.g., setback thermostats) and price-responsive load (e.g., critical peak pricing) — should similarly be apportioned to reflect their benefits, so that cost-effective demand response is a net benefit to both participants and nonparticipants.[59] An hourly assignment method, where the costs of demand response are apportioned

59 Under conventional rate designs, participants (and their classes) generally retain a smaller share of the benefits of demand response (other than incentives for program participation, which may include peak-time rebates) than of energy efficiency programs. Depending on the program design, the incentives for the participants may be reflected in cost allocation and rate design through (1) reduced allocation of costs to the participating customers and classes to reflect improved load shape, (2) payment of incentives (including peak-time rebates) and allocation of those and other utility expenditures as costs, or (3) a combination of the two, as long as the benefits are not double-counted. Dynamic peak pricing may encourage demand response without explicit incentives, with the cost allocation to the participants' class reflecting the improved load shape.

**Figure 24. Illustrative Texas wind and solar resource compared with load shape**




Sources: Adapted from Slusarewicz, J., and Cohan, D. (2018). *Assessing Solar and Wind Complementarity in Texas* [Licensed under http://creativecommons.org/licenses/by/4.0]. Load data from Electric Reliability Council of Texas. (2019). *2018 ERCOT Hourly Load Data*

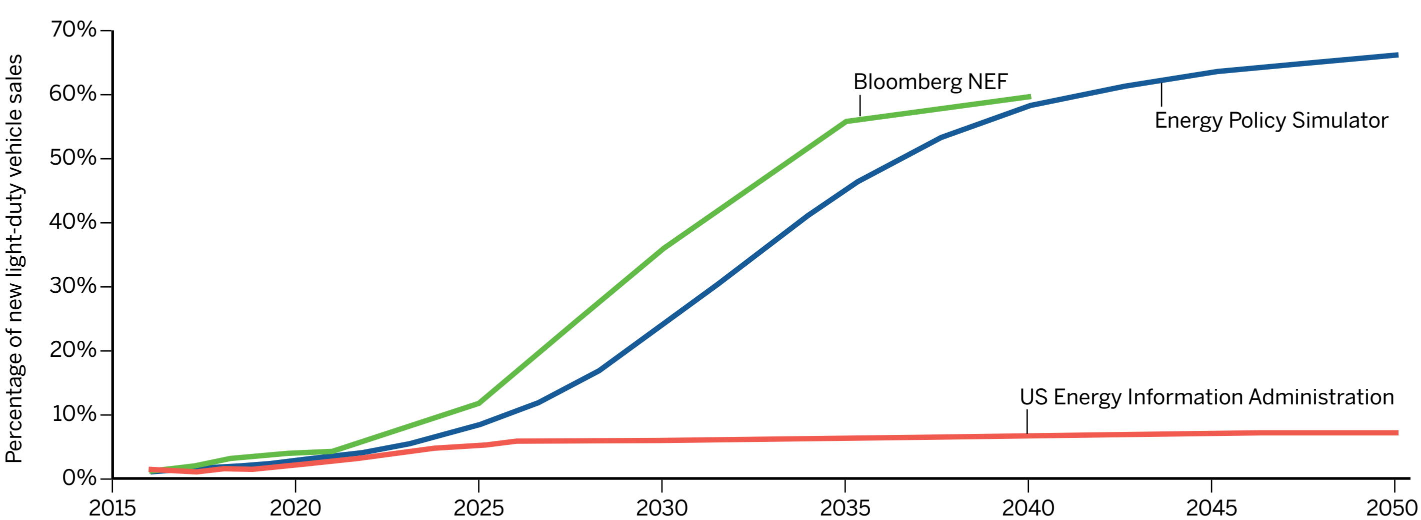
to the hours when it is called upon (to reduce load or provide operating reserves), may help match costs to benefits across classes.

### 7.1.3 Beneficial Electrification of Transportation

Electric vehicles currently use less than 1% of the nation's electricity, but that is expected to rise sharply in the next two decades. However, the precise rate of expansion is uncertain. Figure 25 shows three alternative projections for sales of electric vehicles (Rissman, 2017).

For cost allocation purposes, there are two interrelated issues: how to treat existing customers who adopt EVs as well as new dedicated EV charging accounts, and how to allocate the costs of new utility EV programs, both for demand management and investments in charging stations.

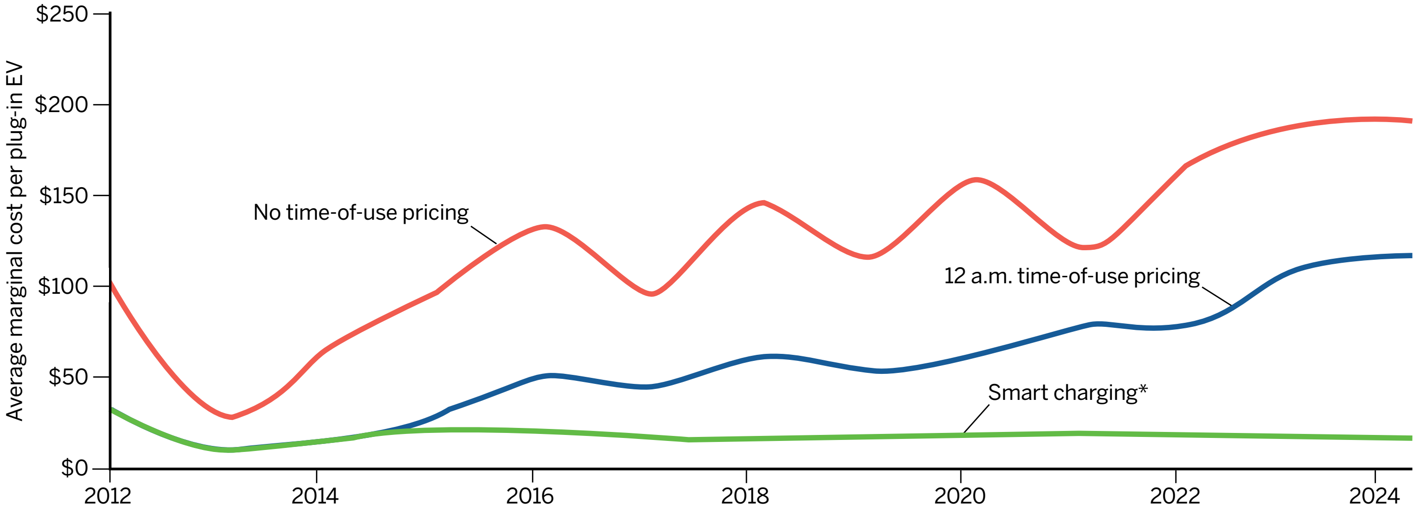
**Figure 25. Forecasts of electric vehicle share of sales**




Note: Projections of U.S. market share of EVs are from the Energy Policy Simulator 1.3.1 BAU case, the Energy Information Administration *Annual Energy Outlook 2017* "No Clean Power Plan" side case, and the Bloomberg NEF *Electric Vehicle Outlook 2017*.

Source: Rissman, J. (2017). *The Future of Electric Vehicles in the U.S.*

**Figure 26. Estimated grid integration costs for electric vehicles**




*Not including costs to implement smart charging technology

Source: Sacramento Municipal Utility District, personal communication, July 8, 2019

EVs are first being adopted in light-duty vehicle market segments, which primarily equates to residential adoption. These EVs are charged predominantly at home; there is a general consensus that home charging comprises over 80% on average (U.S. Department of Energy, n.d.). This home EV charging represents a substantial, but not totally unprecedented, amount of new consumption for a residential customer. The annual consumption for an EV represents slightly less than the consumption required for a typical electric water heater (U.S. Department of Energy, n.d.). If uncontrolled, however, this additional consumption could change the load profile significantly for this subset of customers, potentially leading to additional system costs. For example, if EVs begin to charge at home right after the workday ends and the sun is setting, then this could increase system peak and exacerbate ramping issues.

Between rate classes, changes in load profiles can be easily accounted for in future rate cases as long as there is sufficient load research data on the issue. However, there could also be significant changes in customer load profiles within each rate class. As a result, some analysts have suggested that residential customers with EVs should be a separate rate class. As a threshold matter as discussed in Section 5.2, it is an empirical question whether customers with EVs have distinct cost characteristics from other customers in the same rate class and whether EV adoption is high enough within the rate class to have an impact on the other customers. However, assuming for the sake of argument that these thresholds are crossed, there are alternative ways to address the issue. It is not a given that EV charging will increase system peak or otherwise negatively impact other customers. Time-of-use rates and other demand management programs can significantly lessen these impacts. Figure 26 shows estimated grid integration costs for uncontrolled EV charging and two alternative methods for managing EV load (Sacramento Municipal Utility District, personal communication, July 8, 2019).

Many jurisdictions are moving toward widespread TOU rates for residential customers. If these rates are mandatory for residential customers or even just the default for residential customers with EVs, then that would likely eliminate any cross-subsidy issues between residential customers with and without EVs. Similarly, EVs can be easily integrated into other demand management programs, or programs specific to EVs can be examined.

At some point, similar issues may arise for workplace charging for light-duty vehicles, and it will be desirable to concentrate charging into the hours when generation and delivery system capacity is available and unused. For example, it may be desirable to concentrate workplace EV charging during periods when solar generation is prevalent.

As of this writing, many different heavy-duty EVs are beginning to be adopted. Many jurisdictions have started to adopt electric buses, and a wide range of electric trucks are under development, from postal and parcel urban delivery vehicles to long-haul semitrailers. Fleets of these vehicles will have charging requirements measured in MWs, not kWs, and it may be desirable to locate these charging facilities where they can be directly served from the transmission network, avoiding the primary distribution network altogether. In this case, these sites will be more like large industrial high-voltage customers for cost analysis purposes. Making potential customers aware of this option, to access lower-cost power by locating adjacent to transmission capacity, may help guide the evolution of this market segment on an economical pathway.

Lastly, the development of public DC fast charging, thought by many to be a prerequisite to scale up EV adoption dramatically, is posing a range of new public policy issues. DC fast chargers allow for significantly faster recharging than other charging methods, which may be necessary for a variety of EV use cases, including long-distance travel and adoption in areas where residents cannot charge at home. The power rating of DC fast chargers is typically over 50 kWs per charging port and could increase significantly (Nicholas and Hall, 2018). These characteristics mean that DC fast chargers typically cannot be installed for single-family residential customers. However, DC fast chargers can be installed at many commercial and industrial locations with a sufficient service capacity (e.g., a mall) or connected directly as a stand-alone C&I customer with a separate account.

Many jurisdictions have been wrestling with the proper rate class and rate design for stand-alone DC fast charger accounts. This is because these accounts have a load profile without an obvious correspondence to other C&I rate classes. These accounts have typically been placed in rate classes with significant demand charges. However, given the high kW power rating and low utilization rates at this early stage of EV adoption, high demand charges lead to extraordinarily high bills for these fast charging accounts, at least on an average cost per kWh basis. Given the broader public policy need for public DC fast charging, a number of jurisdictions have begun to take steps to lower bills for these accounts, either through outright discounts or alternative rate structures. To date, there are significant tensions in all of the proposed solutions for these DC fast charging accounts. Given the significant site infrastructure needed to connect the uncontrolled power draw from DC fast chargers, the customer NCP demand for these accounts could be a relevant cost driver. RAP's preferred C&I rate design accounts for this by requiring modest customer NCP demand charges for site infrastructure ($1 to $2 per kW) with other elements of the rates established on a time-varying per-kWh basis. Such a rate would provide the right blend of incentives to manage usage for DC fast chargers through storage or other techniques. As a result, reforming rate design for C&I customers could be the optimal solution to this issue, instead of establishing separate rate classes for DC fast charging or providing arbitrary discounts under existing C&I rate designs.

Several states have also begun to implement utility EV programs, and many more states are considering policies in this area. Expenditures by regulated utilities to support electric vehicles are justified on a wide array of grounds:

- Societal benefits: public health and climate benefits, energy independence and reduced noise.
- Electric system benefits to all ratepayers: new load at beneficial off-peak hours and flexible new loads to optimize ramping.
- Benefits to participating customers and EV drivers: increased convenience, lower total driving costs and the potential to attract new customers to retail businesses.

One category of utility EV programs is quite similar to other energy and demand management programs. In the aggregate, uncontrolled EV load could be a significant addition to peak load that drives many system costs. These utility EV programs encourage, or in some cases ensure, that EV charging will take place during off-peak hours to minimize system stress and long-run electric system costs. The justifications for these programs and the principles for allocating the costs are not very different from other energy management and demand response programs, with functionalization, classification and allocation according to the benefits of the program or alternatively to classes in proportion to customer participation.

In contrast, another major category of utility EV programs does raise new questions. Utility expenditures and investments in support of charging infrastructure are taking a wide variety of forms, including rebates, additional allowances for interconnection costs, and direct utility ownership and operation of end-use charging stations. In most of these programs, participants are expected to bear some of the costs of the charging station, either upfront or ongoing, although a few programs may include full utility ownership and responsibility for all ongoing costs. Drivers of EVs are certainly the most direct beneficiaries of these programs, but there are a wide range of potential benefits for other ratepayers and society at large. Depending on the perspective, this could justify a wide range of cost allocation techniques, including:

- Direct assignment to the customer classes receiving free or subsidized equipment.[60]
- Allocation to all classes in proportion to class revenues or energy use to reflect the benefits to each class from increased sales and reduced average costs.
- Direct assignment to EV program accounts or a broader group of identifiable EV customers as program beneficiaries.[61]

These programs are still quite new at the time of publication for this manual, so many of the important issues are only beginning to be investigated. This is further complicated by cross-cutting issues, such as the integration of energy management programs into utility EV infrastructure investments and the impacts of cost allocation decisions on the competitive EV charging market and charging station providers who do not (or cannot) benefit from utility support.

One logical outcome across these issues could be applying fully loaded time-varying rates to identifiable EV accounts, which may provide higher incremental revenue than incremental costs in those hours. This would have the effect of socializing a substantial portion of EV program costs across a broader group of ratepayers. This would be consistent with efforts to jump-start an infant industry. EV charging station program cost responsibility could be more directly concentrated toward EV drivers over time. This could mean specialized ongoing cost recovery mechanisms, including direct assignment of identifiable EV-related costs. However, a jurisdiction that is seeking to accelerate EV adoption would certainly be free to apply short-run marginal cost-based economic development rates to EV charging development while simultaneously socializing EV program costs to all ratepayers.

### 7.1.4 Distributed Energy Resources

Over the last decade, DERs, particularly rooftop solar, have gained significant traction in many jurisdictions. Many states adopted net metering rules for rooftop solar and other eligible technologies in the 2000s.[62] The federal government also established the investment tax credit for commercial and residential solar systems in 2005, which was thereafter extended and expanded to other solar applications. Starting in the late 2000s, costs for solar panels started to drop quickly. These policies and trends, in addition to a range of additional state policies and incentives, have created a significant new market for rooftop solar. As shown in Figure 27 on the next page, adoption of residential solar accelerated to significant levels in the mid-2010s, with more than 2 GWs of installations annually from 2015 through 2018 (Wood Mackenzie Power & Renewables and Solar Energy Industries Association, 2019, p. 20).

Customer-sited adoption of solar can raise several cost allocation issues. Unlike EVs, distributed solar reduces customer load. At the macro level, for utilities without **decoupling**, this can lead to underrecovery of revenue and necessitate more frequent rate cases. If adoption of distributed solar is captured in the load research data, then cost allocation between rate classes may change over time depending on the cost allocation techniques used.

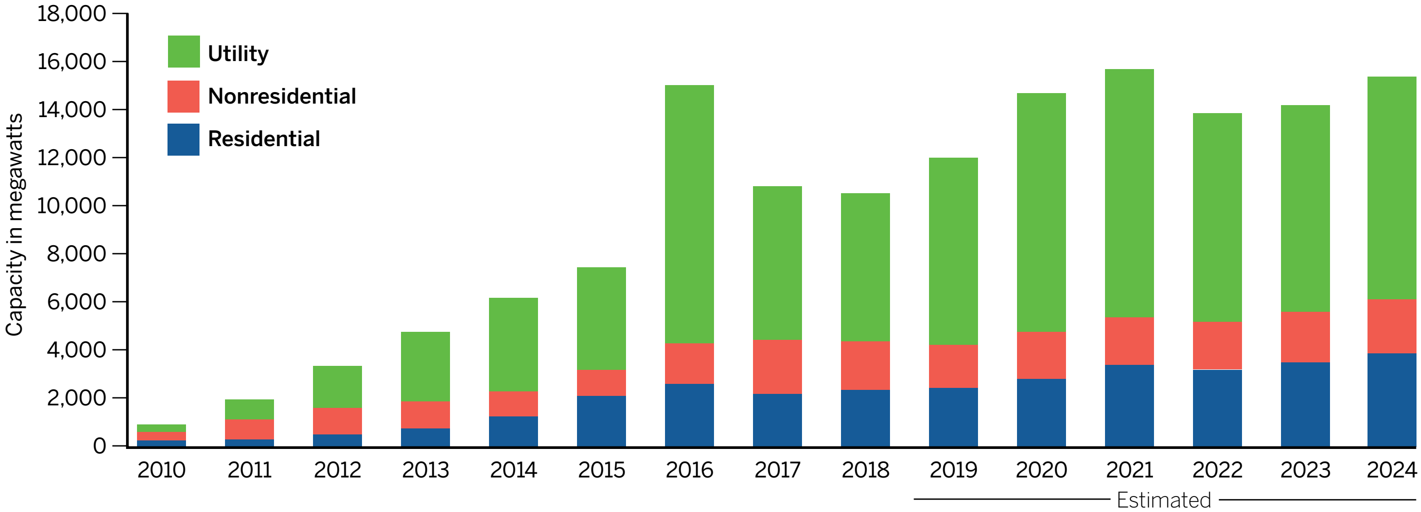
The more difficult issue that jurisdictions around the country have been wrestling with is the possibility of

60 The number of EV program participants in a class, but not the total number of customers in the class, may be relevant to allocation of the costs.

61 There are a number of potential variants on this. Direct recovery of costs from a given customer for installation at that customer's site over time would act as a financing mechanism for that customer. However, specific program costs (e.g., a DC fast charger program) could be recovered through a combination of subsidies from other classes and an ongoing per-kWh basis from the accounts that participated in that program.

62 The 2005 Energy Policy Act added net metering to the PURPA standards that each state was required to consider. Pub. L. No. 109-58 § 1251. Retrieved from https://www.congress.gov/109/plaws/publ58/PLAW-109publ58.pdf

**Figure 27. US solar photovoltaic installations**




Source: Wood Mackenzie Power & Renewables and Solar Energy Industries Association. (2019, March). *U.S. Solar Market Insight*

intraclass cross-subsidies between customers with solar and those without. Many utilities have proposed special rate designs, changes to net metering rules and separate rate classes for customers with solar. As always, the threshold issue for creating a new rate class is whether customers with solar are having material impacts on the other customers. Some utilities and consumer advocates argue that net metering rules allow customers with solar to pay less than their fair share of system costs. It is important to quantitatively evaluate these concerns before making policy adjustments to address them.

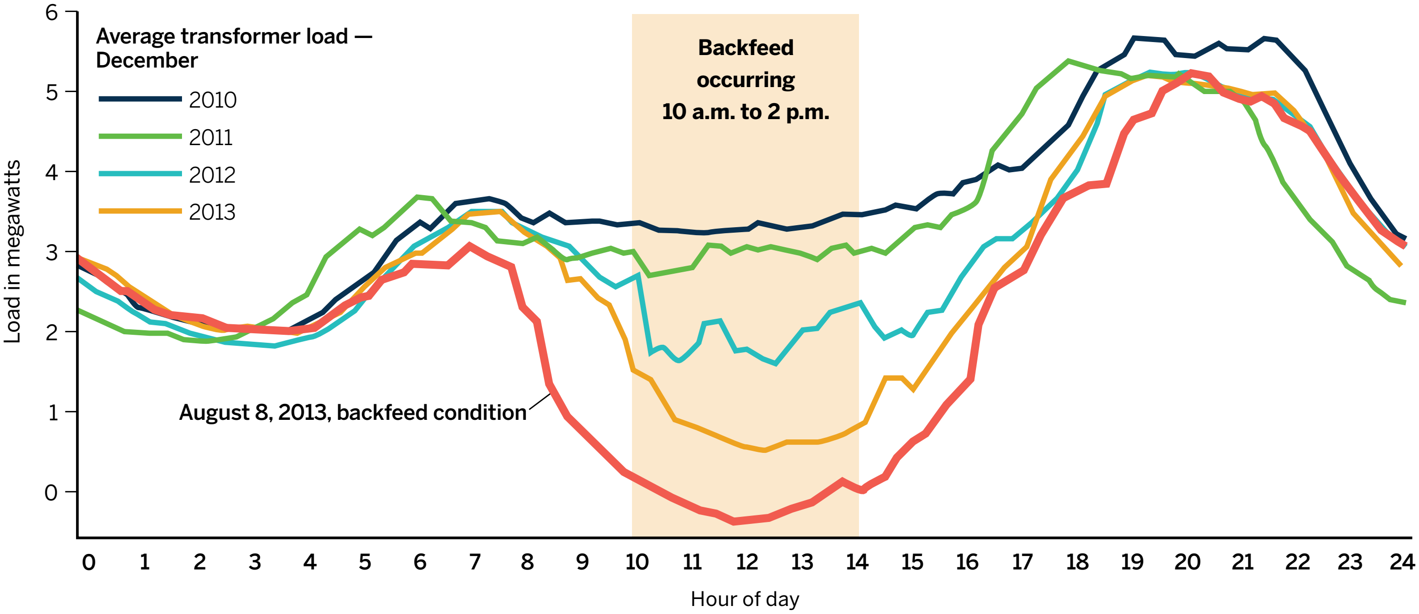
To begin, the levels of distributed solar adoption across the country are quite uneven. While many jurisdictions have significant levels of adoption, particularly those with either strong solar resources (such as California and Hawaii) or supportive state policy environments, many other jurisdictions have low levels of adoption. In jurisdictions with low levels of adoption, the impacts on other customers are necessarily quite small. If only 1% of class load is accounted for by distributed solar, then the worst-case scenario is approximately 1% higher bills for nonparticipating customers, with a strong likelihood of lower impacts given the offsetting benefits of solar generation.[63]

Even in jurisdictions with significant penetration levels of distributed solar, there have been robust debates about the existence of significant cross-subsidies and the proper means to address them. As a general matter, most proposals to establish separate rate classes for distributed solar have been denied so far.[64] Utilities have also proposed higher customer charges and special demand charges for solar customers, which have not been widely adopted. However, a variety of rate design changes have been adopted to better align compensation with value and reduce the potential for unreasonable cross-subsidies. California has begun to address these issues by requiring new residential net metering customers to be placed on TOU rates, a measure that is integrated with a move toward TOU rates for residential customers more generally (California Public Utilities Commission, n.d. and 2016). New York's Value of Distributed Energy Resources proceeding has set up specialized export credit compensation for large distributed energy projects, which include values

63 Net ratepayer impacts from solar policies depend on many factors. In jurisdictions with significant renewable portfolio standard costs or separate solar incentive programs, these costs can be quite different than in jurisdictions where the primary solar compensation policy is net metering. It is important to distinguish whether costs to nonparticipating ratepayers are occurring because of the RPS, dedicated solar incentive programs or net metering policies.

64 The exception to date is Kansas, although separate rate classes for solar customers have been authorized by legislative action in additional states (Trabish, 2017). At the time of this writing, this area of policy is rapidly evolving.

Figure 28. Substation backfeeding during high solar hours




Source: Hawaiian Electric Company. (2014, April 30). *Minimum Day Time Load Calculation and Screening.* Distributed Generation Interconnection Collaborative (DGIC) webinar

for energy, capacity, delivery and environmental externalities (New York Public Service Commission, 2017). Tensions in these debates include differentials between short-term and long-term avoided costs due to distributed generation and how to consider significant societal externalities such as greenhouse gas emissions.

Customer-sited storage is another DER that is expected to grow in importance in the coming decades. Storage can be used to change the load profile for adopting customers and even export energy to the grid if the jurisdiction allows it. Under flat volumetric rates, there is little incentive to manage energy usage with storage and little risk of unusually significant cross-subsidies. However, storage is becoming economically attractive in many jurisdictions to C&I customers that have high demand charges. These demand charges may not be well designed economically, and storage could allow these customers to lower their bills substantially. More generally, well-designed time-varying rates and demand charges can give the proper incentives for energy management through storage, but poorly designed rates will give customers correspondingly poor incentives.

Lastly, higher penetrations of DERs will raise new issues around the allocation of local distribution facilities. As more DERs are added, there will be some systems where primary or transmission voltage customers receive a portion of their power from generating facilities located along distribution circuits. Where this occurs, some provision should be made to treat a portion of the distribution investment as a generation-related cost. Figure 28 shows how some distribution substations may backfeed to the transmission system during solar hours, even if the solar facilities are sited exclusively on the rooftops of secondary voltage customers (Hawaiian Electric Company, 2014).

## 7.2 Changes to Regulatory Frameworks

As also introduced in Chapter 4, many new regulatory issues have arisen since the 1992 NARUC *Electric Utility Cost Allocation Manual*, and some older issues have become more prominent and widespread. These issues include:

- Restructuring and the emergence of organized wholesale markets and **retail competition**.
- Holding company issues due to widespread mergers and new utility conglomerates.
- Performance-based revenue frameworks.
- Proliferation of **trackers** and riders recovering costs outside of rate cases.
- New types of public policy programs.

- Consideration of differential rates of return in cost allocation studies.
- Recovery of **stranded costs**, assets with changed purposes and exit fees.

## 7.2.1 Restructuring

A few issues in cost allocation are specific to restructured electric utilities and **distribution system operators**.

### Administrative and General Expenses

The most important of these issues may be that A&G costs become a larger share of total costs. As utilities have been restructured, not all have trimmed their management ranks or reduced executive compensation in proportion to the reduction in gross revenues. Regulators may need to use utilities that have never had production as proxies to determine appropriate cost levels to be assigned to distribution services and the apportionment of that cost. Even for **restructured utilities** that do not own generation assets, there are costs of maintaining involvement in regional power planning activities, ISO and RTO involvement and NERC involvement that are more closely related to power supply than the ownership and operation of a distribution system. Memberships in various industry organizations may be power supply-related as well.

### Provision of Generation Services

In most states allowing retail competition, the distribution utility also procures and offers, at cost, a **default power supply** service for customers who do not choose an alternative retail electricity supplier.[65] These costs normally will not be included in the cost of service study during a base rate case because they apply only to an optional service and are set through a separate proceeding, generally by competitive bidding to supply individual classes based on their historical load shapes.[66] Any costs incurred by the utility to procure these services should be recovered through the default service, without affecting rate case revenue requirements.

Currently, default service is typically offered on a single residential load profile. We anticipate in the future this will become more granular,[67] at least with respect to time of day and season. This may be done with separate default tariffs for different subclasses of customers, such as multifamily, electric heating or electric vehicle owners. Or it may be done more simply, with a time-varying default service option that applies the same rates to all customers in each period, resulting in different average rates to customers with different usage patterns. A regulator may choose to reconfigure, for retail pricing purposes, these costs on a time-varying basis; if this occurs, the rate analyst must track this change into the cost allocation process.

Some ISOs (for example, ISO-NE, MISO, PJM) apply separate capacity charges and energy charges for power supply delivered to retail providers. Others (such as ERCOT) have eschewed capacity markets, instead concentrating on time differentiation of costs on a volumetric basis and allowing competitive energy prices to rise to levels reflective of scarcity and the value of lost load.[68]

The rate analyst may be in the position of second-guessing the ISO pricing, just as has been the case for natural gas utilities and FERC-approved pipeline charges for decades. If the ISO has treated some costs as capacity-related that can be more economically avoided with storage or demand response within the utility service territory, it may be appropriate to recharacterize these ISO costs as partly capacity-related costs and partly energy-related costs.

### Transmission Costs

In addition to billing for generation capacity and energy in most cases, all ISOs/RTOs bill for transmission service. Most assign transmission costs, project by project, to geographic areas, based on the historical ownership of older

65 Texas has not had any form of default supply since restructuring; all customers must choose a retail electricity supplier.

66 If the utility procures default service at a single price for multiple classes, the regulator should consider whether to differentiate the rates to reflect differences among the classes.

67 See Hledik and Lazar (2016) for a discussion of future pricing options to enable optimal utilization of DERs to meet system and local capacity requirements.

68 We note that the costs of the Alberta capacity market are spread on a time-differentiated volumetric basis rather than a traditional demand charge; this may be a useful model for U.S. ISOs. For a more robust discussion, see Hogan (2016).

facilities and the loads justifying new facilities. If those charges are billed on a capacity basis, the pricing may exceed the cost of avoidance of some transmission capacity but still be necessary for moving energy at nonpeak hours.[69] In this situation, the analyst may need to consider whether some transmission costs are imprudent and should be excluded from the revenue requirement or, perhaps due to how the assets are used, to split these costs between demand and energy.

There are many circumstances where the analyst must look through ISO pricing to determine an appropriate basis for retail cost allocation. For example, ERCOT charges for transmission primarily on a 4 CP basis for the summer months (June through September). Similar approaches may be used in FERC-regulated transmission agreements among affiliates outside of ISOs. These pricing methods and the resulting allocations are administrative simplifications and do not necessarily reflect cost causation. The ISO cost allocations do not control the retail allocation of transmission costs among customer classes or the manner these costs are reflected in rate design.

### 7.2.2 Holding Companies

There have been more than 100 mergers of electric utilities since the 1992 NARUC manual. This phenomenon was accelerated in 2005 when Congress repealed the Public Utility Holding Company Act. This has resulted in very different corporate relationships than existed in the 1980s and has created myriad issues to consider in the cost allocation process, from executive compensation to interservice allocation procedures.

Most utility mergers and acquisitions are justified by projections of more efficient management and a corresponding decline in administrative costs. Determining whether these promises have been realized is a revenue requirement issue beyond the scope of this manual. But the apportionment of administrative costs among unregulated and utility functions, and among utilities within the holding company, are often part of cost allocation. The increased complexity of utility holding companies makes this task more difficult.

Many state utility commissions have taken steps to exclude from the revenue requirement any incentives such as higher executive compensation that reward shareholder benefits (such as for a higher stock price) or rewards for good performance in unregulated operations. Determining the portion of executive compensation that is attributable to the utility operations, as contrasted with corporate profit maximization, is not straightforward. This question may be approached by using senior management costs at public agencies (such as state departments of transportation, health and education or universities) as a proxy for the portion of executive compensation that should be allocated to utility service. Large public agencies may have budgets, employee counts and subordinate levels of management comparable to those of utilities.

Different business operations of a modern utility holding company have different risks and rewards. Although management of a distribution utility is complex, the amount of innovation and risk is fundamentally different than in other business units of the holding company. As noted by the U.S. Supreme Court:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property it employs for the convenience of the public equal to that generally being made at the same time and in the same region of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[70]

By the same logic, a utility is entitled to recover the management costs of a company with similar complexity and risk but not necessarily those of a more speculative business operation.

Shareholder service costs — such as the cost of maintaining shareholder data, issuing dividends, issuing new capital stock and annual meeting costs — must be

69 The Vermont regulator has regularly identified specific nodes where increased efforts for energy efficiency can reduce the need for transmission or distribution capacity upgrades (Vermont Public Service Board, 2007; Vermont System Planning Committee, n.d.). This may provide a foundation for classification of ISO transmission charges and for functionalizing some of these energy efficiency investments as transmission-related or distribution-related capacity costs.

70 Bluefield Water Works v. Public Service Commission, 262 U.S. 679, 692-93 (1923).

apportioned between the non-utility enterprises and the electric utility. Simple methods such as gross revenue or gross capital may be used; more complex methods looking at the number of employees, the contribution to earnings or other factors may also be appropriate.

Holding company insurance costs are substantial. Some are directly related to the utility service business, some are directly related to non-utility operations, and some are shared expenses. As with administrative costs and shareholder service costs, the most appropriate allocation method may need to rely on proxies of enterprises with simpler structures.

### 7.2.3 Performance-Based Regulation Issues

Performance-based regulation has emerged as a central theme in utility regulation. Although the genesis of PBR long predates the 1992 NARUC cost allocation manual, new and different approaches are being developed and implemented today. Early PBR mechanisms were simple price caps or discrete adders for specific investments.[71] The relevant issue for this manual is how to treat PBR costs and benefits in the cost allocation process.

The central concept of PBR is greater emphasis on the achievement of public policy objectives — such as lower customer costs, improved fuel cost performance, better reliability, increased reliance on preferred resources or other discrete goals — coupled with lower reliance on investment levels as a determinant of earnings. This tends to increase the operating expenses to cover the incentives while decreasing both investment and operating expenses when the incentives achieve cost savings.

The incentives may be in the form of a higher allowed rate of return based on achieving policy goals or discrete bonuses for achieving specific objectives. Similarly, penalties for underperformance can take a number of forms. The costs to ratepayers of PBR may include the incentives paid to shareholders as well as expenditures undertaken to achieve the PBR goals.[72] Those costs should be allocated to classes in proportion to the benefits they receive, and penalties returned to ratepayers should be allocated in a manner similar to the distribution of the excess costs that prompted the penalties.

One form of PBR is to provide for multiyear rate plans, where the incentive between rate cases is to achieve designated policy goals. Specific rewards for achievement provide higher earnings between proceedings, rather than mere cost control. This may have the effect of extending the period between general rate proceedings, making it more important that cost allocation in rate proceedings be given adequate attention. This is important because the results may be in place for a longer period than with conventional regulation.

### 7.2.4 Trackers and Riders

The rapid proliferation of tariff riders did not feature in the 1992 NARUC cost allocation manual at all. The earliest of these were **fuel adjustment clauses** adopted in the wake of the oil embargos in the 1970s, but they have now spread to many other categories, including energy efficiency programs, infrastructure spending, nuclear decommissioning and taxes. These riders cause revenue levels to track changes in costs between rate cases in specific categories. Some utilities have 10 or more separate tariff riders, each adjusted between rate cases.

Cost of service studies should be designed for compatibility with the methods that will be used to adjust costs between rate cases. Adjustments between cases may need to be simpler for administrative convenience and may not track cost study results accurately. To maintain consistency, the cost of service study may allocate all costs, with costs to be recovered through riders netted from class revenue requirements as the final step before the design of base rates. Alternatively, allocations of particular cost components from the cost of service study can be applied to the allocation of rider costs (e.g., the residential class might be assigned 34% of any primary distribution upgrades, 30% of purchased renewable energy, and so on).

71 For example, in 1980, the Washington State Legislature approved a 2% incremental rate of return for energy efficiency investments. Two decades later, the Nevada Public Utilities Commission adopted a similar incentive. Both have been allowed to expire.

72 For example, an incentive mechanism to control fuel costs may require capital investments to improve generating units.

Many tariff riders recover only the difference between actually incurred costs and costs estimated in a rate case, which could be reasonably expected to be relatively small. As a result, it often seems relatively fair and administratively efficient to pass these costs on in a simple way. Larger costs may require more detailed methods to track the broader issues laid out in this manual. If general rate cases occur with reasonable frequency, the divergence of riders from the cost of service study between general rate cases probably will be minor.

Many riders are allocated to classes on one of two simple models: a uniform cents-per-kWh surcharge or a uniform percentage surcharge. The uniform cents-per-kWh approach is appropriate for costs associated or correlated with energy usage. The percentage surcharge is rarely appropriate, since it will allocate costs proportionate to all the rate case costs, from meters to substations to (for vertically integrated utilities) baseload generation.

A wide variety of costs are routinely recovered through riders and trackers in many jurisdictions. These costs include the following.

*Fuel and purchased power:* Historically, most of these costs have been recovered through rate riders on a uniform cents-per-kWh basis across all classes.[73] Various fuels and purchased resources (renewables, combined cycle plants, combustion turbines, storage resources) provide different mixes of services. It may be appropriate to unbundle these costs by time period, so that charges more accurately reflect the hours in which the resource is useful and hence the mix of customer loads that use it. The typical uniform cents-per-kWh fuel adjustment clause may be replaced by a more granular rider, with at least time and seasonal differentiation (Hledik and Lazar, 2016). To the extent feasible, the allocation of costs in the rider should reflect the approach used in the general rate proceeding. If costs associated with purchased power are not separated between base rates and the adjustment mechanism in the same manner as utility-owned generating assets, a double-recovery problem may occur, with base rates recovering hypothetical investment costs to serve load growth, while an adjustment mechanism also recovers these costs.

*Decoupling and weather normalization:* Many regulators have adopted measures to insulate utility net income from variations in sales volumes. Some of these mechanisms are decoupling adjustments that take all sales variations into account, while others are strictly limited to sales variation due to energy conservation program deployment or weather. Most of these mechanisms adjust costs that are included in the cost allocation study at test-year levels. The allocation method used for these riders between rate cases should reflect the allocation of costs in the general rate cases. For example, customer costs do not vary with sales levels and should not be used in allocating the costs and credits from weather normalization.

*Required and approved new projects:* Some jurisdictions allow utilities to adjust rates to reflect new investments or operating costs (perhaps limited to specific categories, such as pollution control equipment, storm protection or ISO-approved transmission). The method used to allocate changes in costs between rate cases should be consistent (even if simplified) with the method used to allocate costs in general rate cases.

*Inflation and actuarial changes:* A few states allow flow-through between rate cases of inflation, attrition, statutory tax rates or other exogenous changes in costs, such as labor contracts or pensions. Where possible, these adjustments should be allocated in a manner similar to that used for the underlying costs.

*Flow-through of changes in property taxes:* Property taxes affect all elements of service and are generally assessed on the basis of appraised value, which (depending on the jurisdiction) may be very different from the gross and net book values used to set the revenue requirement.

*Flow-through of municipal taxes and franchise fees:* Some gross revenue taxes and franchise fees are imposed by municipalities and are often directly assigned to customers in that municipality and collected on the same basis they are imposed (e.g., a uniform percentage of gross revenue).

*Storm damage:* Regulators often allow recovery for storm damage in proceedings separate from general rate cases. In many cases, balancing accounts are created for

73 Some utilities adjust power supply riders by estimated line losses by class.

storm damage recovery; after large storms, the amount to be recovered may be adjusted. Storm damage typically affects primarily distribution and transmission costs. The method used for apportionment of changes in tariff riders for storm damage should generally follow the methods used in rate cases for apportioning the relevant costs (but not the cost for unaffected T&D costs, such as meters in most storms).

*Regional transmission charges:* Transmission charges imposed by an RTO or ISO are subject to change between rate cases. These changes may flow through to customers through a broader generation-cost tracking mechanism or a separate transmission rider. To the extent feasible, the costs should be classified and allocated using the same approaches used in allocating bulk transmission costs in the cost of service study. Because peaking assets commonly are located inside or near load centers, bulk transmission requirements tend to be driven more by access to low-cost energy resources, such as baseload generation, as discussed in Chapter 10. If some simple allocator is required for transmission costs outside full rate reviews, an energy allocator is likely to be reasonable.

*Earnings sharing mechanisms:* Some states require utilities to share earnings that exceed some threshold above the allowed rate of return; these are common in conjunction with decoupling mechanisms. Because overall earnings are a broad measure of utility costs compared with revenues, any earnings sharing will likely be spread across all functional areas and should be reflected as a percentage adjustment to overall rates.

## 7.2.5 Public Policy Discounts and Programs

Regulators and legislatures have dictated that utilities offer a range of public policy programs, mostly falling into two categories: (1) discounts or surcharges for certain categories of customers, such as low-income discounts, economic development discounts for industrial customers and area-specific surcharges; and (2) resource-specific incentives for energy efficiency, storage and renewables (including distributed solar).

These programs result in additional costs or redirected revenue requirements to be recovered through base rates, riders or a combination of the two. These revenue requirements may be included in the allocation of total costs, with base rates set to exclude the revenues expected through the riders, or the base rate revenue requirements and the riders can be allocated separately. In any case, the revenue requirements should be allocated among classes in a manner consistent with causality or benefits, without creating excessive administrative burdens in the updating of riders.

Public policy programs for specific resources or resource types (a renewable portfolio standard or other types of clean energy standard) may be justified on current economic benefits, environmental benefits, reliability improvements or the acceleration of emerging technologies and industries with future potential benefits. The costs of these programs are usually allocated either on the basis of program participation by rate class or in proportion to system benefits as they are expected to accrue across rate classes.

## 7.2.6 Consideration of Differential Rates of Return

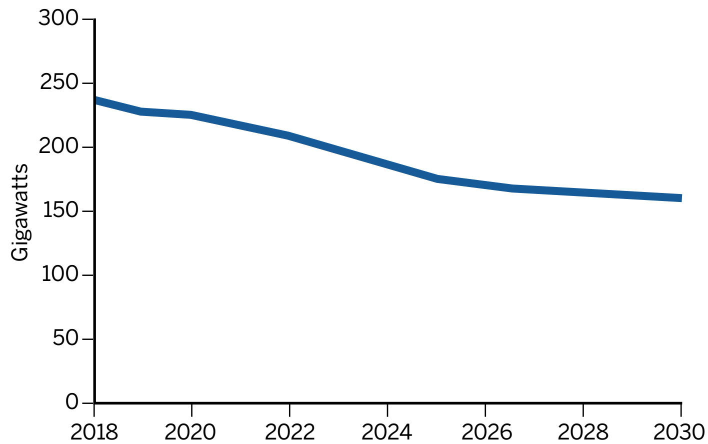
Historically, most cost allocation studies have applied a single rate of return, based on the utility cost of capital, to all capital investment components of the system and to all customer classes. In a more competitive utility environment, this may no longer be appropriate.

Rating agencies and others recognize some utility assets, such as generation, as riskier than other assets, such as distribution. Many utilities have experienced significant disallowances in cost recovery for generation, but the same generally has not been the case with distribution investment. Applying a function-specific rate of return in computing class cost responsibility will assure that this cost follows causation and benefit.

Similarly, some utility customer classes may be viewed as riskier than others. This may be customers with electric space conditioning, whose usage is more temperature-sensitive, creating variability in sales from year to year. Or it may be entire classes of customers whose usage varies with economic conditions, creating what financial analysts call systematic risk that raises the utility cost of capital. Applying a class-specific rate of return in computing class cost responsibility will ensure that low-risk classes do not pay costs more properly attributable to higher-risk classes.

A differential rate of return can be reflected either by assigning different costs of equity and debt to higher- and lower-risk parts of the enterprise, or by assigning a less-leveraged capital structure to the riskier parts of the enterprise and a more leveraged capital structure to the lower-risk parts. Moody's Investor Service applies a higher "business risk" score to generation than to distribution plant. This is then reflected in a higher equity capitalization rate, and thus a higher rate of return requirement, for generation plant (2017, p. 22). This translates into a differential rate of return requirement by customer class because different customer classes use a different mix of generation and distribution assets relative to their total revenue.

**Figure 29. Projections for US coal generating capacity**




Source: U.S. Energy Information Administration. (2019). *Annual Energy Outlook 2019*

## 7.2.7 Stranded Costs, Changed Purposes and Exit Fees

Regulators will face several challenging issues as technology evolves in the electric power industry. Among these will be issues of stranded costs and changing purposes of past investments. Stranded costs occur when an asset is retired prior to being fully depreciated or when an asset is sold at a market price that is below the level included in rate base. Stranded costs were quite significant when the telecommunications industry evolved to computer switching and digital transmission after restructuring in the 1990s and 2000s. The issues will be at least as significant regarding the retirement of current coal and nuclear units. But some assets will be redeployed; for example, coal plant sites that formerly operated as baseload resources may be repurposed to support gas-fired peakers. Transmission lines originally built to serve remote baseload power plants may be redeployed to bring variable renewable energy. These changes to asset usage will raise unique cost allocation issues.

### Generation

Historically, the largest source of stranded costs in the electric industry has been baseload generating resources. Tens of billions of dollars were invested in nuclear units that were abandoned prior to completion in the early 1980s. Many of the nuclear plants that were completed closed long before they were fully depreciated, due to severe damage (e.g., TMI 2, Crystal River, Trojan, Rancho Seco and San Onofre), large investment requirements or unfavorable economics. Today, innovation is rendering many units uneconomic in a narrow financial sense, excluding externalities of any kind, even when they are still mechanically sound. As shown in Figure 29, the U.S. Energy Information Administration (2019) projects that nearly 100 GWs of coal generation will be retired between 2018 and 2030. Most of this is due to economic obsolescence, but it also reflects changing public policies around air pollution and climate.

Economic obsolescence of coal plants is primarily a result of lower-cost wind, solar and natural gas.[74] Although some policymakers are considering whether these coal plants, or the broader coal industry, need to be supported with financial incentives, there has been widespread support for this coal retirement trend for both cost and environmental reasons. In contrast, many states have been implementing policies to slow or stop nuclear retirements, in part because of the plants' climate benefits. In many cases, regulators have been actively involved in the decision to retire these units through integrated resource planning processes. In some

74 Public Service Company of Colorado decided to retire two coal units at the Comanche generating facility in Pueblo after bids for wind and solar energy were so low that the operating costs of these coal plants were deemed uneconomic (Pyper, 2018).

cases, legislatures have driven the retirements. Although a retirement usually concludes with a regulatory determination of what part of the cost is recoverable, a separate decision must be made on how to reflect the allowed costs in the cost of service methods and rate design of the utility.

Cost allocation analysts are not typically charged with determining the portion of abandoned project costs that electricity consumers or shareholders should bear. However, if these costs are included in rates, analysts are charged with determining how to reflect those costs in utility cost allocation studies and ultimately in rate design. If the plants were allocated in one way when operating and that method changes after termination, then the costs are shifted from one set of customers to another.

In other circumstances, plants have been converted from their original purpose to different purposes. The most common of these are baseload units, originally built to provide year-round service, being converted to peaking or seasonal generation or held in reserve for droughts or other contingencies. The cost allocation framework for the new purpose may be fundamentally different from the historical method based on historical usage.

In all of these cases, the cost of service study must reflect the allowed costs for abandoned or repurposed units. Should the costs be allocated based on the original intended purpose? Or should these costs be allocated based on the last useful purpose for the units? There is no easy answer.

Similar issues arose from the divestment of generation assets during restructuring. In jurisdictions with restructured utilities,[75] millions of retail customers have begun taking generation services from retail electricity providers or public aggregators and no longer pay the regulated utility directly for power supply. In many cases, this was politically achievable only by providing a method to compensate the utility for any stranded costs. This compensation typically was accomplished through a nonbypassable per-kWh charge on all distribution system customers, although in some cases specific exit fees were established so that departing customers made a one-time lump sum payment. Often this was done without reference to how the underlying costs are allocated among classes.

During restructuring proceedings in New England, many of the mid-Atlantic states, Illinois and Texas, regulators used an incremental valuation approach to recover the difference between the embedded costs and market values of generation assets. This included:

1. The net plant for utility-owned generation minus the sales price for those assets. That difference was negative for most hydro and fossil assets and positive for most nuclear assets.[76]
2. Costs of decommissioning for retired plants, especially nuclear units.
3. Payments to terminate or restructure long-term power purchase agreements.
4. Profit or loss from operating any residual utility-owned generation and selling power into the competitive market.[77]
5. Annual differences between payments for continuing power purchase agreements and the value of the power in the capacity and energy markets.[78]

Stranded cost charges are set to recover the sum of categories 4 and 5, the amortization of the balances in categories 1 through 3, any carrying charges for unamortized balances and any over- or undercollections in earlier periods.[79] Categories 4 and 5, and hence the overall surcharge, may be positive or negative. The surcharge continues until the stranded capital costs are recovered (or gains distributed) and all continuing cash flows end. In some jurisdictions,

75 New York, New Jersey, Pennsylvania, Maryland, Delaware, the District of Columbia, Ohio, Illinois, California, Texas and most of New England, as well as some customers in Michigan and Oregon. In Canada, Ontario has restructured similarly.

76 Certain utilities, notably all those in Ohio and some in Pennsylvania, New Jersey and Maryland, were allowed to transfer their generation assets to an affiliate at an estimated market value, rather than imposing a true market test from full divestment.

77 This approach has been applied to generation for which sale has been delayed (e.g., several nuclear units) or is impractical (e.g., ConEd's generation units located at or serving its steam distribution system) and to resources, such as renewables, that the utility is allowed to develop.

78 Long-term wholesale sales agreements may be bought out or treated in the same manner as power purchase agreements.

79 The costs in the first three categories frequently were refinanced through low-risk bonds, in a process called securitization.

restructuring surcharges have continued into 2019, in some cases as a credit.

Lastly, **community choice aggregation** has raised a similar set of issues in California, in part because a choice of energy supplier is not allowed more generally, and the utilities have procured long-term supply resources for a variety of reasons. Locales that form community choice aggregators, primarily counties, are allowed to contract directly with generators for power supply, which may vary from the resource characteristics of the utility's standard supply. In the meantime, market supply costs have declined, especially for renewables, and the migration of customer generation requirements from the utility to the aggregators can result in some stranded power costs, at least according to the utilities. California has selected a complex solution, imposing a power charge indifference adjustment, a type of exit fee with annual updates, on the community choice aggregators to recover the difference between actual utility costs and market prices. Rather than having a single charge for all customers to cover above-market costs, California has created a highly controversial process to set a charge for the customers of the aggregators and the direct marketers. The California experience illustrates the benefits of consistent allocation across customers, as opposed to the development of special rates for special groups of customers.

Any charge for stranded assets or costs should be temporary, only until the specific costs regulators allow are recovered.

### Transmission

There is less history with transmission abandoned costs, but many lines are now being repurposed. Originally they were built to connect distant coal or nuclear baseload generating resources to urban load centers. Many of these were classified and allocated in the same manner as the baseload generation, with at least a portion of the cost classified as demand-related and allocated on some measure of peak demand. Today, with new natural gas generation being sited close to load centers and older coal and nuclear baseload units retired, these lines are being repurposed to transport economic energy from distant markets, including opportunity purchases, or to carry power from new wind and solar generating resources.[80] This is a very different use and provides very different economic benefits to consumers.

Some transmission lines are disused due to generation retirement. Although the inclusion of these costs in the rate base of the owning enterprise is a revenue requirement issue, the classification and allocation of any cost allowed by the regulator is a cost allocation issue. Some transmission lines may become economically obsolete due to the deployment of DERs within the service territory, obviating the need for some distant generation and its associated transmission lines. In this situation, the rate analyst is faced with the question of how to classify and allocate the fully or partly stranded costs.

Some lines may be repurposed from providing firm service from baseload resources to providing seasonal economic service without a clear connection to peak demand. In this situation, the costs may still be fully justified as economic and in the public interest, but a change in allocation method may be justified. An hourly assignment method will ensure that these costs are recovered in the hours when the economic energy is flowing.

### Distribution

There have been very few regulatory disallowances of any magnitude for distribution plant, in part because the mass accounting methods do not identify specific segments. For example, when a large industrial facility closes, the investment in distribution facilities serving it typically remains in the regulated revenue requirement and continues to be classified and allocated in traditional ways. But technological evolution may result in higher rates of retirement or repurposing.

Some assets will be disused at many hours, due to deployment of DERs. Some CHP facilities will be entirely self-sufficient much of the time, with reliance on grid-supplied energy only during maintenance outages or periods of economical options. Distribution lines originally designed

80 Clear examples of this are found in the desert Southwest, where retirement of coal units in New Mexico, Arizona and Utah that formerly served California utilities is freeing up transmission that is being repurposed for moving variable renewables. State legislation mandated the retirements; economic conditions are driving the repurposing of these facilities.

to provide continuous service may be used only for a limited number of hours. The rate analyst must consider which is appropriate: applying the same methods used before DERs were installed or a different classification and allocation method in light of the changed circumstances.

In some areas of Hawaii, distribution circuits are back-feeding to the transmission system at midday; these lines are now serving a power supply integration function for many hours of each day.

The flow may be bidirectional. Power will flow into the lines from distant generation or storage during hours of darkness and into the grid for redelivery during high solar hours. The cost may be entirely prudent, but the traditional allocation methods may not accurately assign costs to the beneficiaries. An hourly allocation method may be appropriate for these circumstances, with the costs flowing to the consumers actually using the power when it is generated, rather than being apportioned to the generators or to customers not receiving power at certain hours.

### Cross-Functional Repurposing

There are myriad examples of utility resources once needed for a particular function being repurposed for an entirely different function. For example, a former power plant site may become a location for a distribution warehouse. The power plant was functionalized as generation and allocated based on demand and energy factors. The distribution warehouse is a component of general plant, and the allocation method may be very different. One challenge for the rate analyst is tracking changes in how assets are being used, to keep the allocation framework consistent with the utilization of the assets.

# 8. Choosing Appropriate Costing Methods

In general, facilities shared among multiple users, as well as expenses and investments benefiting all ratepayers, should be apportioned based on measures of shared usage. Facilities that are uniquely serving individual customers should be sized to their individual needs, and the costs should be directly associated with those customers. Overhead costs, such as A&G expenses and general plant, are not costs that are subject to a "technically correct" allocation.[81] Pragmatically, these costs can be fairly divided among classes based on a measure of usage or even revenue since there is not necessarily a link between system cost drivers and these costs.

The first task in choosing a cost allocation method is to ascertain the objective of the study: Is it focused on short-run

### Many factors influence cost allocation method selection

The appropriate choice of a detailed allocation approach and the most appropriate method may be affected by such factors as:

- Are the utility's loads growing, shrinking or stagnant?
- Does the utility have a mix of different types of supply resources to serve varying load levels?
- Does the utility rely on transmission facilities to deliver power from remote baseload, hydro or renewable energy resources?
- Is generation mostly spread among load centers, or is supply concentrated within certain portions of the service territory?
- Does the utility's supply mix include variable renewable resources, such as wind and solar?
- Does the utility have sufficient load density to support the distribution system with energy sales, or is the load so sparse that other revenues are required to pay for distribution (as is the case for some cooperatives)?
- Are peaking resources located inside the service territory near loads, or are they dependent on transmission from distant sources?
- How do the utility's customers break down into classes and subclasses that have significantly different cost characteristics?
- Does the utility have reasonably reliable hourly load data, by class?
- Does the utility have demand response resources that can help meet extreme peak requirements?
- Does the utility have storage resources that can shift generation or loads among time periods?
- Does the utility's load peak in the winter, in the summer or both?
- Do different customer classes peak at different times of the day or different seasons of the year?

Each of these questions bears on the most appropriate cost allocation approach. A mix of resources requires a method that appropriately treats that variety of resources differently in classification and allocation. Variable resources require a method that assigns their costs to the hours in which they produce benefits. The location of supply resources determines whether the method must apportion transmission costs among multiple purposes.

81 Bonbright described some distribution costs as strictly unallocable: "But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs" (1961, p. 348). The same "unallocable" characteristic may apply to other system costs in an evolving industry.

equity considerations or rather on efficiency considerations? Is the system an optimal system or a suboptimal system for today's needs? Most advocates of using embedded cost studies point to the direct link with the revenue requirement and spreading that revenue requirement among multiple customers. Although there is a wide range of embedded cost methods, all of them apportion the existing revenue requirement, and rates based on the results should produce the allowed amount of total revenue.

Within this broad sense of equity, however, the methods selected may result in vastly different results. For example, in one docket, the Washington Utilities and Transportation Commission considered the results of several approaches to embedded cost of service studies, presented by the utility, the commission staff and intervenors. The commission did not rigorously follow any of them but found that the range of these studies defined an appropriate range in which the revenue allocation should be based.

Another goal of cost allocation is long-run efficiency to guide consumer consumption based on where costs are going, not where they are.[82] The use of long-run marginal costs attempts to do this in the cost allocation phase of rate-making, and indeed this was the position that some advocates took in the hearing era after passage of PURPA. Their position was that all costs should be forward-looking to encourage long-run efficiency and that past costs cannot be "saved," so there is no point using them for cost allocation or rate design.

But marginal costs are not the same as current costs making up the revenue requirement, and some method is needed to reconcile (up or down) the results of a marginal cost study with the revenue requirement. The methods to do this include proportionality (adjusting all class revenue requirements by the same percentage) and various methods of focusing on certain aspects of cost in adjusting allowed revenues in consideration of marginal cost. These methods have been highly controversial, as discussed in detail in Part III.

In the short run, it is desirable to optimize the incurrence of variable costs such as fuel, labor and purchased energy. Consideration of short-run marginal costs focuses on exactly this. If systems have excess generating capacity, power costs are low; with deficient capacity (or fuel or water shortages), power costs are high. One problem with establishing cost allocation on the basis of short-run marginal costs is that few costs other than power supply vary significantly in the short run. Although utilities do reduce staffing during a recession and may defer maintenance, these are minor cost savings. Therefore, the costs considered are only a very small fraction of the revenue requirement.

During periods of energy shortage, such as the California energy crisis of 2000-2001, regulators may believe that short-term deviations from traditionally used long-run marginal cost theory are appropriate. In California's case, the commission approved both higher thresholds for energy efficiency investments and very sharply increased tailblock rates.

One issue that has been raised with respect to various short-run and NERA-style marginal cost studies is that they capture only a limited window in time, when utility resources may be imperfectly matched to utility customer needs. This is discussed in detail in Part IV.

A market that has short-run marginal costs that are equal to long-run marginal costs is said to be in equilibrium. When in equilibrium, the cost of producing one more unit of output with existing resources is relatively expensive, because all of the low-cost resources are already fully deployed, resulting in short-run costs that exactly match the cost of building and operating new resources. For electric generation, this might mean running a peaker to provide energy in many hours because available lower-cost units are fully deployed. In this situation, there would be no difference between marginal cost studies using different time horizons.

But electric utilities are almost never in equilibrium, for several reasons:

- Forecast and actual loads, costs, technologies and resource availability change faster than the system can be reconfigured, leaving systems with capacity excess or deficiency and resources that are poorly suited to current needs.
- Utilities maintain reserve margins for reliability, which often results in energy dispatch costs that are lower than

82 Canadian hockey great Wayne Gretzky is widely quoted as having said: "I skate to where the puck is going to be, not where it has been."

the fixed and variable costs of a new efficient generating unit. A system with marginal running costs high enough to justify new construction will tend to have a relatively low reserve margin.

- In other markets, short-run costs can be allowed to rise, with the tightening available supply rationed by pricing, and the short-run cost becomes the price of outbidding other users. For electricity, that approach would lead to blackouts.
- Transmission and distribution do not have short-run marginal costs comparable to the long-run costs of new equipment. Short of allowing overloads until lines and transformers fail, there is no way to bring a T&D system into equilibrium.
- As energy generation transitions from fossil generation with high running costs to zero-carbon resources with low running costs and high capital costs, it will be harder to match short-run and long-run costs.

A state of disequilibrium can severely affect some customer classes if a marginal cost study is based on short- to medium-term costs. If a shortage of power supply exists, it will severely affect large-volume customer classes; if a surplus exists, it will severely affect residential and small commercial customers.

In the following chapters, we address in detail how each type of cost should be considered in different approaches to cost allocation. The methods will be different for every utility because every utility has a different history and a different mix of resources, loads, costs, issues and opportunities. The appropriate method for each utility may be slightly different. It is driven by the mix of customers, the nature of the service territory, the type of resources employed and the underlying history that guided the evolution of the system. No single method is appropriate for every utility, and no single method is likely to produce a noncontroversial result. Many regulators will seek consistent methods to be applied to all utilities in their state, which may require compromise from the most appropriate method for each individual utility. In Chapter 27, we discuss how regulators can use the results of quantitative cost studies to actually determine a fair allocation of costs among classes.

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# Part III:

# Embedded Cost of Service Studies

# 9. Generation in Embedded Cost of Service Studies

This chapter addresses the allocation of generation costs, including investment-related costs, operation and maintenance costs and fuel costs. As noted in Section 6.1, equivalent changes in the allocation of a cost category among classes can be achieved by changing functionalization, classification or the choice of allocation factor.[83] That section discusses the relevant issues at a high level, and this chapter delves more deeply into the underlying concepts and analytical techniques.

This chapter is not generally relevant to cost allocation for utilities that have restructured and no longer procure generation resources, as long as the generation prices suppliers offer (directly to customers or to the utility for default service) are differentiated by rate class. High-level cost allocation issues with respect to generation and default service are discussed in Section 7.2.

As discussed in Chapter 3, utilities acquire and maintain different types of generation resources, with distinct operating capabilities, to meet a range of needs including low-cost energy, reliability, **load following** and environmental compliance. Different classification and allocation methods may be necessary to equitably allocate the costs of different types of generation resources. In more recent years, energy efficiency, expanded demand response, distributed generation and energy storage — all of which can be located where load relief is most valuable — have expanded the utility's options to meet load growth or reduce demands on aging assets without building transmission, distribution or central generation facilities.

Fuel costs, purchased power and dispatch O&M costs, such as the short-run variable cost of pollution controls, are typically classified as energy-related. The other categories of generation costs have generally been classified as being driven by some combination of energy (total energy requirements to serve customers, plus losses) and demand (some measure of loads in the hours that contribute to concerns about the adequacy of generation supply to meet loads). Energy use is sometimes broken into TOU periods, so that different types of costs are spread over the hours in which they are used, as discussed further in Section 9.2 and Chapter 17.

When there are multiple cost-based approaches for estimating a classification or allocation factor, a compromise among the results may be appropriate. For example, various measures of reliability risk (emergency purchases, operation of peakers, interruption of load, inadequate operating reserve) may be distributed differently across the months, and the regulator may reasonably select a generation demand allocator averaging across the results of those measures. Similar conditions might apply for varying estimates of the firm-capacity equivalent for wind plants or other inputs.

Some cost of service studies identify other classifications of generation costs, such as ancillary services. These components are generally very small compared with total generation costs, and some ancillary services (automatic generation control, black start capability, uplift) can be difficult to relate to class load characteristics.

## 9.1 Identifying and Classifying Energy-Related Generation Costs

Many regulators have recognized that energy needs are a significant driver of generation capital investments and nondispatch O&M costs. In modern utility systems, generation facilities are built both to serve demand (i.e., to meet capacity and reliability requirements) and to produce energy economically. The amount of capacity is largely determined by reliability considerations, but the selection of generation technologies and thus the cost of the capacity are

83 As mentioned previously, the third step is usually called allocation, which is the same as the name of the entire process. Some analysts refer to this third step as factor allocation in an attempt to prevent confusion.

largely determined by energy requirements.[84] For variable renewables, particularly wind and solar, the effective capacity (in terms of the reliability contribution) of the generators is much smaller than their nameplate capacity, and the costs are mostly undertaken to provide energy without fuel costs or air emissions. Energy storage systems provide both energy benefits (by shifting energy from low-cost to high-cost hours) and reliability benefits, while demand response is used primarily to increase reliability.

As discussed in the text box on pages 78-79, some older cost of service studies classified a wide range of capital and nondispatch O&M costs as demand-related on the grounds that the costs were in some manner fixed, without regard for cost causation. This approach, known as **straight fixed/variable**, is anachronistic and does not reflect cost causation.[85]

Table 12 shows the capital and O&M costs estimated for new conventional generation units from the 2018 Lazard's *Levelized Cost of Energy Analysis* report.[86] Although the original costs and current plant in service and O&M costs of older units will vary, the general relationships have been consistent.

This section first discusses the insights on this issue from competitive wholesale markets. This is followed by four different classification approaches and two joint classification and allocation approaches, then a discussion of other technologies and issues.

**Table 12. Cost components of conventional generation, 2018 midpoint estimates**

| Technology | Capital cost (per kW) | Fixed operations and maintenance (per kW-year) | Variable operations and maintenance (per MWh) |
|---|---|---|---|
| **Combustion turbine** | $825 | $12.50 | $7.40 |
| **Combined cycle** | $1,000 | $5.75 | $2.80 |
| **Coal** | $3,000 | $40.00 | $2.00 |
| **Nuclear** | $9,375 | $125.00 | $0.80 |

Source: Lazard. (2018). *Lazard's Levelized Cost of Energy Analysis — Version 12.0*

## 9.1.1 Insights and Approaches From Competitive Wholesale Markets

The ISOs/RTOs that operate energy (and in some cases, capacity) markets — specifically ISO-NE, NYISO, PJM, ERCOT, MISO and the SPP — provide examples of how the recovery of capital investment and nondispatch O&M costs naturally splits between energy and demand. The pricing in these markets can provide both a **competitive proxy** for classifying generation costs and a benchmark to check the reasonableness of other techniques.

ERCOT has no capacity market, and all costs are recovered through time-varying energy charges. Those energy charges are heavily weighted toward a small number of hours, which do not tend to have particularly high loads; the highest-load hours are not the highest-cost hours. Figure 30 on the next page shows the hourly load and Houston Hub prices for 2017 (Electric Reliability Council of Texas, 2018, for load data; ENGIE Resources, n.d., for pricing data).

Prices generally trend upward with load, but the highest-priced hours are spread nearly evenly across load levels.

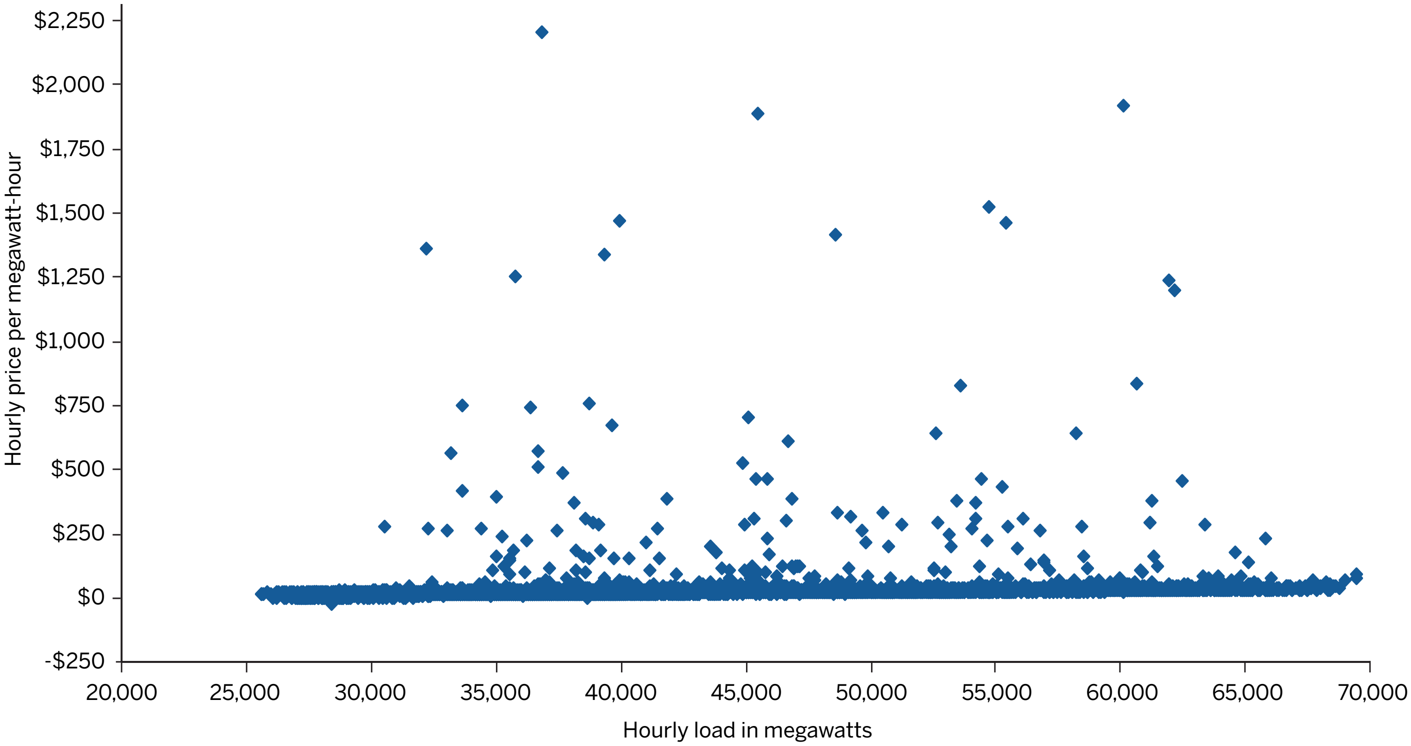
In 2017, the highest-priced 1% of hours (with prices over $160 per MWh) would have provided 18% of the annual net margin for a baseload plant with no variable cost, 53% of the margin for a plant with a variable cost of $20 per MWh (perhaps a combined cycle unit), and 77% of the margin for a plant with a $30-per-MWh variable cost (such as a recently built combustion turbine), assuming ideal dispatch and no

84 "Citing both past operating experience and future resource planning, the Division [the PSC intervention staff] notes that resources with higher energy availability are chosen over those with lower energy availability. Since energy plays a role in the selection of least-cost resources, the Division concludes that some weight needs to be given to energy in planning for new capacity, and the current weight of 25 percent is reasonable. We find the qualitative argument offered by the Division to be … convincing." (Utah Public Service Commission, 1999, p. 82). See also Washington Utilities and Transportation Commission (1993, pp. 8-9).

85 The term "straight fixed/variable" is imported from FERC's rate design method for wholesale gas supply, where utilities, marketers and very large customers contract for capacity in a portfolio of individual pipeline and storage facilities. As is true for many electric wholesale purchased power contracts, these gas contracts require that the buyers pay for investment-related costs regardless of how they use the resources and pay for variable costs in proportion to their usage. This approach is workable at the wholesale level but is not applicable to retail cost allocation, where the utility bundles a portfolio of generation assets for all of its customers.

86 The coal cost in the table is Lazard's low end, since the high-end cost "incorporates 90% carbon capture and compression" (Lazard, 2018, p. 2), which is in use on only one existing utility coal unit, SaskPower's Boundary Dam. The $3,000/kW value is also consistent with the costs of the last three coal plants completed by U.S. regulated utilities (Turk, Virginia City and Rogers/Cliffside 6, all completed in 2012). Actual current costs of various vintages of resources will vary for each utility.

**Figure 30. ERCOT load and real-time prices in 2017**




Sources: Electric Reliability Council of Texas. (2018). *2017 ERCOT Hourly Load Data*; ENGIE Resources. *Historical Data Reports*

outages. Those 88 hours representing the costliest 1% occurred in every month and almost the whole range of annual loads.

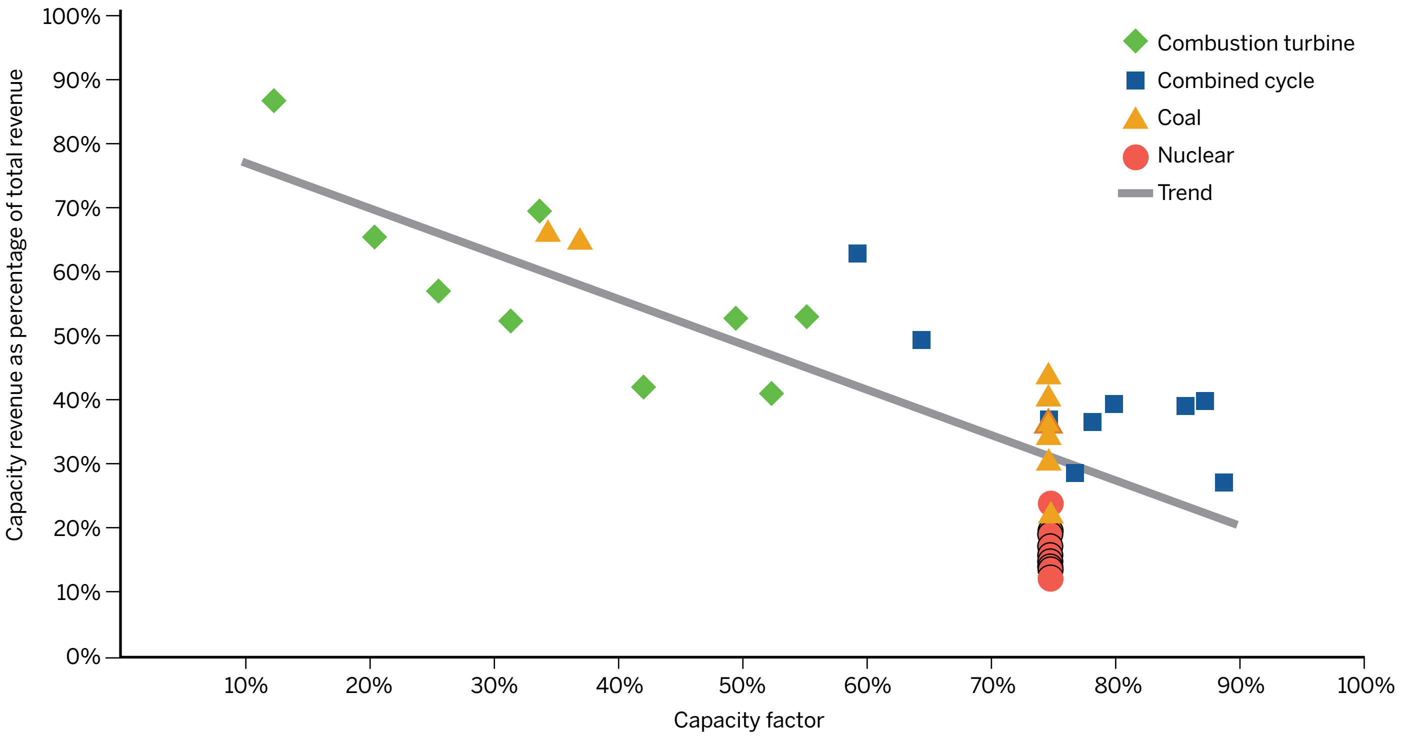
In contrast, the 1% of highest-load hours would have provided 5.1% of the margin for the baseload plant, 2.4% for the intermediate plant and 2% for the combustion turbine. This cost pattern suggests that, at least in some systems, generation costs should be time-differentiated but that load is not a good proxy for the highest-price periods. Classes with the ability to shape load to low-cost periods (with demand response or storage) may be much less expensive to serve than those with inflexible load patterns.

Regardless of how the top hours are chosen, the ERCOT data indicate that most of the long-term power supply costs are not recovered from the few peak hours and thus should not be considered demand-related. For a load shaped like the ERCOT average load, only about 3% of the generation costs were associated with the 1% of highest-load hours, and about 20% were associated with the 1% of highest-price hours.

In New England, the ISO-NE external market monitor estimated that the net revenues available to pay the capital investment and nondispatch O&M costs of a typical recently built gas combined cycle unit would have been about 25% to 60% from the energy market and the remainder from the capacity market, depending on the year (Patton, LeeVanSchaick and Chen, 2017, p. 13). The comparable values for nuclear units were almost all from the energy market (Patton et al., 2017, p. 17).

The PJM independent market monitor reports the capacity revenues and the net energy revenues (i.e., energy revenue in excess of fuel and variable O&M) for a variety of plant types (Monitoring Analytics, 2014, pp. 219-222, 2019, pp. 335-339). These are the revenues available to pay for the capital investment and nondispatch O&M costs and thus represent the market allocation of these costs for the plants. Figure 31 on the next page shows the portion of these costs recovered through capacity payments for four types of new plants (gas-fired combustion turbine and combined cycle units, and hypothetical new coal and nuclear) in each year

**Figure 31. Capacity revenue percentage in relation to capacity factor in PJM**




Data sources: Monitoring Analytics. (2014 and 2019). *2013 State of the Market Report for PJM, 2018 State of the Market Report for PJM*

2009 through 2017 (Monitoring Analytics, 2014, 2019).[87]

The concept displayed here is that units with a high **capacity factor** tend to make more of their revenue from energy markets instead of from the capacity market. In this set of PJM data, energy revenues cover 14% to 60% of the combustion turbine costs, 38% to 74% of combined cycle costs, 56% to 73% of baseload coal plant costs, about 34% of the costs of economically dispatched coal units, and 77% to 89% of nuclear costs over the nine-year period. The values for 2017 were 39% for modern combustion turbines, 87% for combined cycle units, 65% for coal and 20% for nuclear. Current values for PJM or the relevant load zones could be used as the demand classification percentages for vertically integrated utilities in PJM (e.g., IOUs in Kentucky, Virginia and West Virginia, and municipal and cooperative utilities in several states).

The market monitoring unit of the NYISO provided similar analyses for the various pricing zones of that RTO, as shown in Table 13 (Patton, LeeVanSchaick, Chen and Palavadi Naga, 2018, Table A-14, with additional calculations by the authors). The upstate zones have relatively low capacity prices, while the Hudson Valley and New York City have very high capacity prices, and Long Island has intermediate prices. Both capacity and energy revenues vary among zones within each of these three areas, between load pockets within zones and among combustion turbine types.

**Table 13. Energy portion of 2017 net revenue for New York ISO**

| | Generator type | | |
|---|---|---|---|
| Zone | Combustion turbines | Combined cycle | Steam |
| **Upstate** | 72% to 80% | 71% to 79% | 42% to 55% |
| **Long Island** | 52% to 70% | 62% to 76% | 21% to 57% |
| **Hudson Valley and New York City** | 31% to 49% | 34% to 55% | 6% to 29% |

Sources: Patton, D., LeeVanSchaick, P., Chen, J., and Palavadi Naga, R. (2018). *2017 State of the Market Report for the New York ISO Markets;* additional calculations by the authors

87 The independent market monitor assumed that a nuclear plant would operate at a 75% capacity factor and made the same assumption for the coal plant through 2015; the capacity factors for the gas-fired plants and for coal in 2016 and 2017 are determined from the economic operation of the units.

## 9.1.2 Classification Approaches

Many utilities and regulators acknowledge that a large portion of generation investment and nondispatch O&M costs is incurred to serve energy requirements. There are two categories of methods to classifying these costs as energy-related and demand-related. First, average-and-peak is a top-down approach that uses high-level data on system loads and costs. Second, there is a range of bottom-up approaches that examine the drivers for costs on a plant-specific basis:

- Base-peak and related methods.
- Equivalent peaker method.
- **Operational characteristics methods**.

As a general matter, the bottom-up approaches are preferable for classifying generation costs. The average-and-peak approach is well suited for shared distribution system costs, as discussed in Section 11.2.

### Average-and-Peak Method

The average-and-peak approach can be applied in classification, when classifying a portion of costs as energy-related and the remainder as demand-related, or in developing a generation capacity allocator that reflects both energy and demand. When using this approach as a classification method, the **system load factor** percentage is classified as energy-related and the remainder as demand-related.[88] When used as an allocation factor, the average-and-peak factor for each class is:[89]

$$\frac{A_C}{A_S} \times \mathrm{SLF} + \frac{P_C}{P_S} \times [1\text{-SLF}]$$

Where A = annual average load = energy ÷ 8,760

P = peak load

C = class

S = system

SLF = system load factor = (annual energy) ÷ (peak load × 8,760)

The system load factor, and hence the average-and-peak approach more generally, varies over time independent of the mix of the utility's generation resources and does not respond to changes in that mix unless those changes are accompanied by retail pricing that follows the cost structure.

In addition to changing as loads change, the average-and-peak approach ignores the mix of resources and costs. This approach would produce the same classification of plant for a system that was entirely composed of gas-fired combustion turbines (with low capital costs and high fuel costs) or of coal-fired plants (with high capital costs to produce lower fuel costs).

Thus, while the average-and-peak method for generation costs may sometimes fall in the range of reasonable results, it is neither logical nor consistent.

### Base-Peak Methods

Various utilities and other analysts have proposed to subfunctionalize generation resources (in the simplest case, between baseload and peaking plants) and classify each category of generation in a different manner. For example, peakers may be classified 100% as demand-related, while baseload resources are classified 75% to demand and 25% to energy, or some other location- and situation-specific ratio.

More advanced analyses have subfunctionalized generation among base, intermediate and peak categories, known as BIP classification. The base generation might be defined as all nuclear and coal plants, with the intermediate being gas-fired steam and combined cycle plants and the peak units being combustion turbines, storage and demand response. Alternatively, base plants might be any unit that operated at more than a certain capacity factor (for example, 60%), peakers those that ran at less than 5%, and intermediate anything between those 5% and 60% capacity factors. Or, rather than using capacity factor (which can be low due to forced outages, maintenance or economic dispatch), the

88 This method is sometimes called the system load factor approach. It has also been called "average and excess" because a fraction of cost equal to the system load factor is allocated on energy and the excess of costs on a measure of peak loads (Coyle, 1982, pp. 51-52).

89 This average-and-peak allocator should not be confused with the average-and-excess demand allocator described in the 1992 NARUC *Electric Utility Cost Allocation Manual,* which allocates a portion of costs in proportion to average load and the excess in proportion to each class's excess of peak load over its average use. That legacy average-and-excess allocator is essentially just a peak allocator (Meyer, 1981).

generation classes can be defined using operating factor (the ratio of output to equivalent availability). At an extreme, each generation type, or even each unit, can be classified separately.

While the base-peak classification approach and related methods are highly flexible, that is both their greatest strength and a great weakness. The strength is that the method can be modified to accommodate the diversity of generation resources; the weakness is that the method requires a set of decisions about the definition of the generation classes and the classification percentage for each class. The base-peak method is connected to actual utility planning only at the highest conceptual level and provides limited guidance for the nitty-gritty details of traditional classification.

One of the challenges of the base-peak approach relates to the changing usage of generation resources. For example, several units that were built to burn coal in baseload operation have been converted to burn natural gas and thus run mostly on high-load summer days.[90] These units operate as peak or intermediate resources (depending on the definitions used in the particular analysis), but most of the capital costs are attributable to the original baseload design. This problem may be ameliorated by removing those additional costs from the base-peak or BIP computation and directly classifying them as energy-related.

Recent technological changes pose additional challenges and opportunities for expanding the base-peak approach from two generation profiles, or the three profiles of the BIP method, to a full analysis of the use of generation resources. Decades ago, it was reasonably accurate to treat generation resources as being stacked neatly under the load duration curve in order of variable costs. The growing role of variable output renewable resources, additional storage and economic demand response reduces the accuracy of those simple models. Resources like wind and solar do not fit neatly into the BIP categories, providing service in distinct time patterns that may not be related to system loads. At the same time, many utilities have access to much more granular detail on hourly consumption by customer.[91] The BIP method can be expanded to reflect conditions (output by several classes of conventional generation, solar, wind and storage; energy use for storage; usage by class) in as many time periods (or load levels, or bins combining consumption and generation conditions) as desired, even down to an hourly allocation method. Usage and hence costs could thus be assigned directly to the classes using power at the times that each resource provides service.[92]

### Equivalent Peaker Method

The equivalent peaker method,[93] discussed at length in the 1992 NARUC *Electric Utility Cost Allocation Manual,* attributes as demand-related the portion of investment in each resource that would have been incurred to secure a peaking resource, such as demand response or a combustion turbine.[94] Peaking resources are usually treated as 100% demand-related, while intermediate and baseload plants are classified as partly energy and partly demand.

If only peak load had been higher (and other needs were already satisfied) in the years in which the utility made the bulk of its generation construction decisions, it would have likely met that increased load by adding peaker capacity.[95] Utilities historically have justified building baseload capacity by relying on these plants' long hours of use and lower fuel

90 Some coal plants that once ran as baseload resources have been taken out of service in low-load months to reduce O&M costs. This includes Nova Scotia Power's Lingan 1 and 2 (Barrett, 2012), Luminant's Monticello and Martin Lake (Henry, 2012) and the Texas Municipal Power Agency's Gibbons Creek (Institute for Energy Economics and Financial Analysis, 2019).

91 Most utilities have long known the hourly generation by unit.

92 Some utilities refer to their classification method as BIP, even though it does not reflect the differences in costs among the various types of generation. For example, the Louisville Gas & Electric and Kentucky Utilities 2018 "BIP" computation classified nondispatch generation costs this way: 34% (the ratio of minimum to peak load) to energy; 36% (the 90% ratio of winter peak to summer peak, minus the 34% energy allocation, or 56%, times the 65% of the peak-period hours that occur in winter) to the winter peak demand; and the remaining 30% to the summer peak demand (Seelye, 2016, Exhibit WSS-11). This approach has no cost basis.

93 In some jurisdictions, this is called the peak credit method.

94 This approach is sketched out in Johnson (1980, pp. 33-35) and described in more detail in Chernick and Meyer (1982, pp. 47-65).

95 To some extent, the peakier load would likely allow for development of more demand response and load management. Estimating the potential and costs for these resources under hypothetical load shapes may be difficult.

costs.[96] This incremental capital cost (often called capitalized energy or "steel for fuel") is attributable to energy requirements, not demand. The investment-related costs of baseload resources above and beyond the cost of peaking units are incurred to serve energy load, not demand. Treating these costs as demand-related overstates the cost of meeting demand and understates the costs incurred to meet energy requirements. This phenomenon has been understood since the 1970s and 1980s:

> [T]he extra costs of a coal plant beyond the cost necessary to build a combustion turbine should all be allocated [on] energy. The rationale for this allocation is that the marginal cost of capacity in the long run is just the lowest-cost technology required to meet peak load, which is typically a combustion turbine. Choosing to invest beyond this level [of combustion turbine capital cost] is justified not on capacity grounds, but on energy grounds. That is, the extra capital cost of a coal plant allows the utility to use a low-cost fuel and avoid higher-cost fuels (Kahn, 1988).

However, there are several additional issues with this concept in the modern electric system. First, the method does not adapt well to wind and solar, where the capital investment is primarily justified by avoiding fuel costs but the installed capital cost per nameplate MW may be little different from the cost of a peaker. An intermediate or baseload plant that is not much more expensive than a contemporaneous peaking resource would be classified as mostly demand-related, while very expensive plants are classified as mostly energy-related. And often, peaker units are used to provide energy when baseload units are not operating or to provide power for off-system sales.[97]

Under the equivalent peaker method, the demand- or reliability-related portion of the cost of each generation unit is estimated as the cost per kW of a peaker (usually a simple-cycle combustion turbine) installed in the same period, times the effective capacity of that unit, adjusted for the equivalent availability of a peaker.[98] The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.

However, the simple version of this calculation typically will overstate the reliability-related portion of plant cost because it assumes a steam plant supports as much firm demand as would the same capacity of (smaller) combustion turbines. Due to higher forced outage rates, lengthy maintenance shutdowns and the size of units, a kilowatt of steam plant capacity typically supports less firm load than a kilowatt of capacity from a small peaker. A system with a peak load of about 6,500 MWs and a 65% load factor could achieve the same level of reliability with 80 units of 100 MWs (8,000 MWs, or a 23% reserve) or 19 units of 600 MWs (11,400 MWs, or a 75% reserve), assuming the units all have a 6% **equivalent forced outage rate** and that the load shape can accommodate all required maintenance off-peak. Increasing the equivalent forced outage rate to 10% would increase the required reserve for the 100-MW units to about 40% and for the 600-MW units to 90%. Even with the 6% equivalent forced outage rate, if the load factor were 96%, the reserve requirement would rise to 30% with 100-MW units and 90% with 600-MW units.

Figure 32 on the next page shows the gross plant per kW for combustion turbines as of 2011, from FERC Form 1 data (Federal Energy Regulatory Commission, n.d.). These values include the original cost of the units, plus capital additions since the plants entered service, minus the cost of any equipment retired. This tabulation includes all non-CHP simple-cycle combustion turbines for which cost data were available.[99] Some of the later combustion turbines in this sample may not be pure peakers, since manufacturers

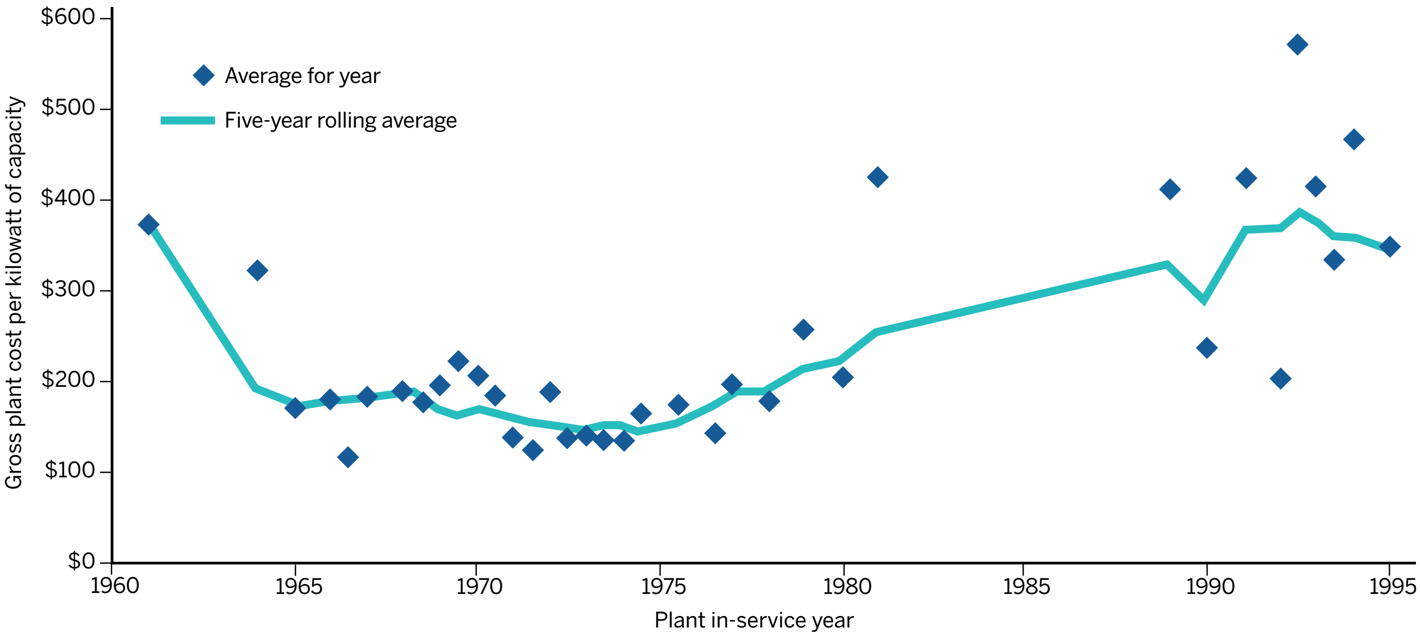
96 Similar reasoning applies to the decision to add renewable resources, substituting investment for fuel costs. See footnote 120.

97 During the 2000-2001 California energy crisis, oil-fired peakers in the Pacific Northwest operated at high monthly capacity factors because they were exempt from both gas supply constraints and California emissions regulations. U.S. Energy Information Administration Form 906 for 2000 and 2001 demonstrates the incremental oil burn in 2000 and 2001, particularly for Puget Sound Energy.

98 In the future, the reference peaking capacity might be an increase in demand response cost or storage peak output capacity, without an increase in energy generating capability. The reference peaker should always be the least-cost option for providing reliability.

99 Municipal and cooperative utilities and non-utility generators (both those under contract with utilities and those operating in the merchant markets) do not file FERC Form 1 reports, so their units are not included in this analysis. The municipal and cooperative utilities typically retain financial and operating records that are compatible with the FERC system of accounts, allowing comparison of the data for a specific utility's nonpeaking resources with national data on contemporaneous peaker costs.

**Figure 32. Cost of combustion turbine plant in service in 2011**




Data source: Federal Energy Regulatory Commission Form 1 database

developed more expensive and more efficient designs, including steam injection.

For comparison, coal plants built in this period generally cost from several hundred dollars per kW to more than $2,000 per kW; the latest vintage coal plants cost as much as $3,000 per kW. Steam plants fired by gas and oil (and not converted from coal) tend to have a wide range of gross plant costs, from the prices of contemporaneous combustion turbines to perhaps twice those costs. Nuclear plants generally have gross plant costs well above $1,000 per kW, up to $8,000 per kW. Combined cycle plants have usually been 20% to 50% more expensive than contemporaneous combustion turbines.[100]

The capital costs of various types of generating capacity can be compared with the costs of peakers in several ways, including the following:

- Comparing recent or current gross plant costs for other generators with the corresponding cost of peakers, as discussed above.
- Comparing recent or current net plant (gross plant minus accumulated depreciation) costs for nonpeaking generators with the corresponding net plant costs of contemporaneous peakers. This comparison is theoretically the most appropriate basis for classifying generation rate base, which is based on net plant. Unfortunately, net plant is not generally publicly reported by plant or unit, so most cost analysts will have a difficult time implementing this approach. In addition, many utilities have depreciated peakers at a faster rate than steam plants, resulting in lower net plant for a peaker than for a steam plant with the same initial cost, additions and retirements. This results in a higher percentage of the steam plant costs being classified as energy-related based on net plant than gross plant. It is not obvious whether the additional classification to energy is more equitable than the result of the gross plant allocation.
- Comparing the cost of building the actual mix of generation today with the cost of building a peaking-only system today.[101] This approach avoids the problem of

100 These cost ratios are provided to explain the importance of identifying the demand-related portion of generation investment. Any application of the equivalent peaker method should compare the costs of the utility's existing plants to the costs of contemporaneous peakers, using the most comparable estimates of the costs of peakers, reflecting geographical and other differences.

101 The peaking-only system might include combustion turbines, demand response and storage resources.

estimating the cost of building peakers at various times in the past. But many existing plants could not be built today as they currently exist — a new coal plant may require scrubbers, nitrogen oxide reduction, closed-system cooling and other features that the existing coal plant does not have.[102] Other plant types, such as oil- and gas-fired boiler units, no longer make economic sense and would not be built today. Determining the cost of building a new 1970s-style coal plant or a gas-fired steam plant may be much more difficult than determining the cost of peakers in the 1970s. And for some technologies, the costs of new construction do not meaningfully reflect the costs of the plants currently embedded in rates. For example, as expensive as the nuclear units of the 1980s were, the nuclear units currently under construction are much more expensive. Conversely, the costs of wind turbines have fallen dramatically since the 1980s. Comparing today's costs for those resources to the costs of new peakers would probably overstate the energy-related portion of the costs of an old nuclear unit and understate the energy-related portion of the costs of an old wind farm.

Whether the comparison uses gross plant in service, net plant in service or hypothetical new construction, the data sources should be as consistent as possible. It would not be appropriate to compare the current book value of an actual plant with the cost of a hypothetical plant in today's dollars (Nova Scotia Utility and Review Board, 1995, p. 18).

Table 14 shows the equivalent peaker method analysis that Northern States Power Co.-Minnesota (a subsidiary of Xcel Energy) used in its 2013 rate case filing (Peppin, 2013, Schedule 2, p. 4).[103] The capacity portion for each plant type is the ratio of the peaking cost ($770 per kW) to the plant type cost. For example, the peaking cost is 20.9% of the cost of the nuclear plant, so 20.9% of the nuclear investment is treated as capacity-related. The company uses its estimates of the replacement costs of each type of generation and applies the results to each capital cost component (gross plant, accumulated depreciation, deferred taxes, etc.).

**Table 14. Equivalent peaker method analysis using replacement cost estimates**

| Resource type | Cost per kW | Capacity-related share of cost | Energy-related share of cost |
|---|---|---|---|
| **Peaking** | $770 | 100% | 0% |
| **Nuclear** | $3,689 | 20.9% | 79.1% |
| **Fossil*** | $1,976 | 39.0% | 61.0% |
| **Combined cycle** | $1,020 | 75.4% | 24.6% |
| **Hydro** | $4,519 | 17.0% | 83.0% |

*The "fossil" resource type appears to be coal- or gas-fired steam.

Source: Peppin, M. (2013, November 4). Direct testimony on behalf of Northern States Power Co.-Minnesota. Minnesota Public Utilities Commission Docket No. E002/GR-13-868

This is not a very realistic comparison, for reasons discussed above. Many of the plants could not be built today, and some have complicated histories of retrofits and repowering. The nuclear replacement cost appears to be particularly optimistic compared with the cost of nuclear power plants under construction today.

Table 15 on the next page shows an alternative analysis based on the Xcel Energy Minnesota subsidiary's actual investments in each plant type at the end of 2017, from Page 402 of its FERC Form 1 report (Federal Energy Regulatory Commission, n.d.).

The results of the two analyses are generally consistent, except for the classification of the combined cycle resources. These plants are of more recent vintage than the others; a fairer comparison, using peaker costs contemporaneous with the in-service dates of each of the other resources, probably would result in a lower energy classification of the combined cycle resources and higher energy classification for the coal and nuclear units.

The equivalent peaker method does have limitations. Perhaps most importantly, it requires cost comparisons of individual generation units with peakers of the same vintage. Utilities installed combustion turbines as far back as the early 1950s, but the technology was widely installed only in the late 1960s. The oldest remaining combustion turbine owned

102 Many hydroelectric projects could not be licensed if they were proposed today.

103 The company calls this a plant stratification analysis.

**Table 15. Equivalent peaker method analysis using 2017 gross plant in service**

| Resource type | Capacity (MWs) | Plant in service: Cost | Plant in service: Cost per kW | Excess over combustion turbine: Cost | Excess over combustion turbine: Cost per kW | Energy-related share of cost |
|---|---|---|---|---|---|---|
| **Combustion turbine** | 1,114 | $291,000,000 | $261 | N/A | N/A | 0% |
| **Nuclear** | 1,657 | $3,448,000,000 | $2,081 | $3,016,000,000 | $1,820 | 87% |
| **Coal** | 2,390 | $2,156,000,000 | $902 | $1,532,000,000 | $641 | 71% |
| **Combined cycle** | 1,266 | $939,000,000 | $742 | $609,000,000 | $481 | 65% |
| **All resources** | 6,427 | $6,834,000,000 | $1,063 | $5,157,000,000 | $802 | 75% |

Data source: Federal Energy Regulatory Commission Form 1 database records for Northern States Power Co.-Minnesota

by a utility filing cost data (Madison Gas and Electric's Nine Springs) entered service in 1964. The paucity of earlier data complicates the use of the equivalent peaker method for classifying the costs of older plants. This problem is gradually fading away, as all pre-1970 nuclear is gone and much of the pre-1970 fossil-fueled steam capacity has been retired or is nearing retirement, but the issue remains for classifying hydro plant costs and the few remaining old fossil fuel plants (U.S. Energy Information Administration, 1992).

One solution to the problem of classifying the investment in very old, little-used steam plants is to treat that cost as entirely demand-related. Since these units often represent a very small portion of generation rate base, this solution may be reasonable.

A full equivalent peaker analysis would compare the product of the actual depreciation charges for the nonpeaking plants with the product of the peaker depreciation rate and the peaker-equivalent gross investment for the same reliability contribution. Since the classification of rate base usually ignores the higher accumulated depreciation of peakers compared with the accumulated depreciation for other generation resources of the same vintage (which tends to overstate the demand-related portion of generation rate base), it is also generally symmetrical to classify generation depreciation expense as proportional to the demand-related portion of gross plant (which will tend to understate the demand-related portion). If classification of one of these cost components is refined to reflect the difference in depreciation rates, the other cost component should be similarly adjusted.

As is true for plant in service, the nonfuel O&M costs of steam plants are generally much higher than the nonfuel O&M costs of combustion turbines. Typical O&M costs per kW-year are $1 to $10 for combustion turbines, $10 to $15 for combined cycle plants, $10 to $20 for oil- and gas-fired steam plants, $40 to $80 for coal plants and more than $100 for nuclear plants. Table 16 shows how the capacity-related O&M for conventional generation might be classified between energy and demand, using the utility's actual nonfuel O&M

**Table 16. Equivalent peaker method classification of nonfuel operations and maintenance costs**

| Resource type | Capacity (MWs) | Nonfuel operations and maintenance: Cost | Nonfuel operations and maintenance: Cost per kW-year | Excess over combustion turbine: Cost | Excess over combustion turbine: Cost per kW-year | Energy-related share of cost |
|---|---|---|---|---|---|---|
| **Combustion turbine** | 1,114 | $4,170,000 | $3.74 | N/A | N/A | 0% |
| **Nuclear** | 1,657 | $215,880,000 | $130.28 | $209,680,000 | $126.54 | 97% |
| **Coal** | 2,390 | $33,490,000 | $14.01 | $24,550,000 | $10.27 | 73% |
| **Combined cycle** | 1,266 | $16,380,000 | $12.94 | $11,650,000 | $9.20 | 71% |

Data source: Federal Energy Regulatory Commission Form 1 database records for Northern States Power Co.-Minnesota costs; the data are 2017 numbers from FERC Form 1, Page 402, for Northern States Power Co.-Minnesota (Federal Energy Regulatory Commission, n.d.).

Table 16 does not include the company's wind resources, which average about $30 per kW-year in O&M, since MISO credits wind with unforced capacity value at only about 15% of rated capacity, or about 17% of the value of an installed MW of typical conventional generation. The demand-related portion of the wind capacity is thus less than $1 per kW-year, and the wind O&M is almost all energy-related.[104]

### Operational Characteristics Methods

The operational characteristics methods classify generation resources (units, resource types, purchases) based on their capacity factors or operating factors. Newfoundland Hydro classifies as energy-related a portion of the cost of each oil-fueled steam plant equal to the plant's capacity factor (Parmesano, Rankin, Nieto and Irastorza, 2004, p. 22). At first blush, this approach appears to roughly follow the use of the resource, with plants that are used rarely being treated as primarily demand-related and those used in most hours classified as predominantly energy-related. Unfortunately, the use of capacity factor effectively classifies more of the cost to demand as the reliability of the resource declines.

A better approach would be to use the resource's operating factor, which is the ratio of its output to its equivalent availability (that is, its potential output, if it were used whenever available). This approach would classify any resource that is dispatched whenever it is available (e.g., nuclear, wind and solar) as essentially 100% energy-related. That may be seen as an overstatement, since those resources generally provide some demand-related benefits and are sometimes built to increase generation reliability, as well as to produce energy with little or no fuel cost.

## 9.1.3 Joint Classification and Allocation Methods

Although most cost of service studies classify capital investments and capacity-related O&M as either demand-related or energy-related, classify power and short-term variable costs as energy-related, and then allocate energy-related and demand-related costs in separate steps, two approaches accomplish both at once. These are the probability-of-dispatch (POD) and **decomposition** approaches.

### Probability of Dispatch

The POD approach is the better of the two.[105] Methods using this approach are generically referred to as probability of dispatch, even for versions that do not explicitly incorporate probability computations.[106] A simplified illustrative example of power plant dispatch is shown in Figure 33 on the next page, under the utility load duration curve. The example uses only four types of generation: nuclear, coal, gas combined cycle and a peaking resource consisting of a mix of demand response, storage and combustion turbines. An actual POD analysis might break the generation data down to the plant or even unit level and may need to include load management and demand response as resources. This simplified example also does not illustrate maintenance, forced outages or ramping constraints.

Off-system sales and purchases can be added or subtracted from the load duration curve when they occur, or they can be subtracted or added to the generation available in each hour or period. Similar adjustments may be needed to reflect the charging of storage and operation of behind-the-meter generation.

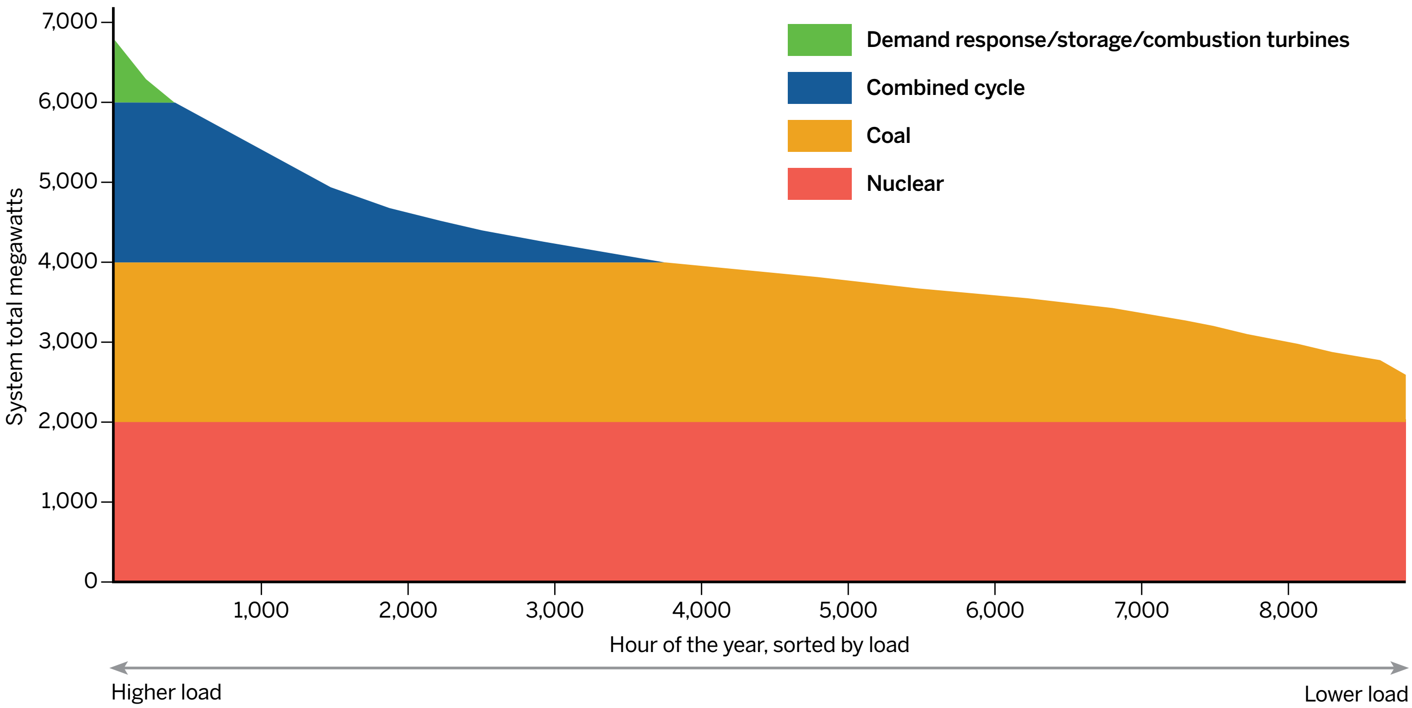
Figure 34 shows the composition of demand in each hour for the same illustrative system, divided among three customer classes. In this example, the residential class peak load occurs when load is high but not near the system peak.

104 The nonfuel O&M costs per kW for Northern States Power's two small waste-burning plants and its small run-of-river hydro plant are even higher than the nuclear O&M and hence are effectively entirely energy-related, even if the hydro plant provides firm capacity.

105 The Massachusetts Department of Public Utilities explained its preference for this method as follows: "The modified peaker POD results in a fair allocation of embedded capacity costs because this method recognizes the factors that cause the utility to incur power plant capital costs and because this method allocates to the beneficiaries of fuel savings the capitalized energy costs that produce those savings" (1989, p. 113).

106 For an example of the POD method, see La Capra (1992).

**Figure 33. Simplified generation dispatch duration illustrative example**




This situation might arise for a winter-peaking residential class in a summer-peaking system, or an evening-peaking residential class in a midday-peaking system.

Note that the three customer classes need not peak at the same time. On a high-load summer day, the primary industrial class might peak in the morning, the secondary commercial class at 1 p.m., and the residential class in the evening. Large commercial buildings typically experience their peak load in the summer, since large buildings require cooling in most climates. If a large percentage of home

**Figure 34. Illustrative customer class load in each hour**

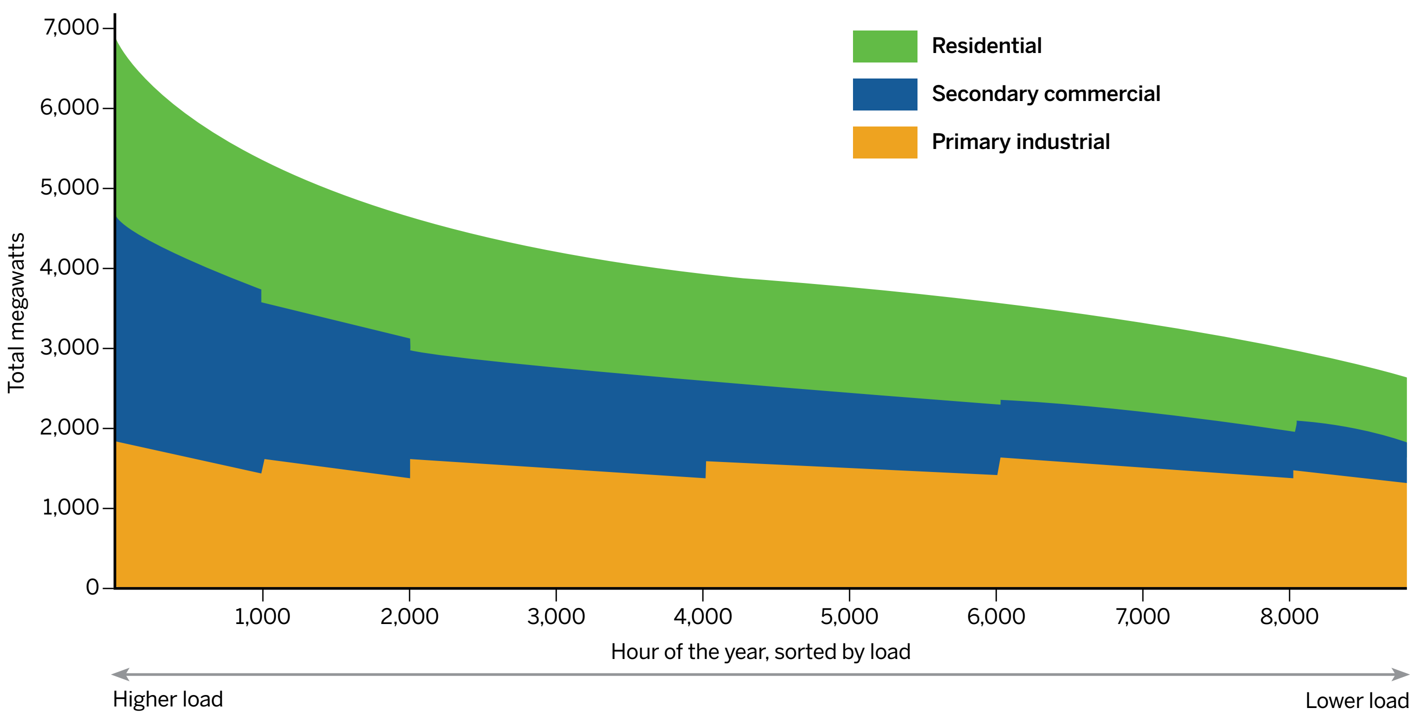


**Table 17. Class share of each generation type under probability-of-dispatch allocation**

| Customer class | Generation source: Nuclear | Coal | Combined cycle | Peaking resources |
|---|---|---|---|---|
| **Residential** | 34% | 34% | 32% | 31% |
| **Secondary commercial** | 28% | 29% | 39% | 42% |
| **Primary industrial** | 38% | 37% | 29% | 27% |

heating is electric, the residential class is likely to experience its highest load in the winter, even in places like Florida. The industrial class loads may peak in a variety of seasons, driven by vacation and maintenance schedules, variation in inputs (e.g., agricultural products) and demand, and other factors. The system peak may occur at a time different from all of the customer class NCP demands.

Table 17 shows how the costs of each generation resource would be allocated to the classes in the illustrative example in Figure 34. In the lowest-load hours, when nuclear is serving 80% of the energy load, the industrial class uses half the system energy and hence half the nuclear output; in the highest-load hours, when nuclear is serving about 29% of the load, the industrial class uses about 27% of the system energy. Averaged over the year, the industrial class uses 38% of the nuclear output. In the hours that the combustion turbines are running, the industrial class uses only 27% of the peaking resources' output, since the residential and commercial classes dominate loads in that period.

The commercial class is responsible for the largest share of the summer peak and hence of the combustion turbine costs but the smallest part of the low-load hours and hence the lowest share of the nuclear and coal costs. Every class pays for a share of each type of generation.[107]

The POD method has been applied with a wide range of detail. The generation "dispatch" over the year may represent historical or forecast operation, equivalent availability or capacity factor, seasonal variation (due to maintenance outages, hydro output, natural gas price, off-system purchases and sales), actual hourly output (reflecting planned and random outages and unit ramping constraints) and other variants. The POD method is thus one approach to hourly allocation. Ideally, dispatch and class loads should use the available data to match costs with usage as realistically as possible.

The POD approach has some limitations. Most importantly, it does not consider the reason that investments were incurred, only the way they are currently used. The costs of an expensive coal plant no longer needed for baseload service and converted to burn natural gas and operating at a 10% capacity factor to meet peak loads might be allocated in exactly the same way as the costs of a much less expensive combustion turbine operating at 10% capacity factor.[108] The excess costs of the converted coal plant are due to its historical role of providing large amounts of energy at then-attractive fuel costs; those costs were not incurred for the 10% of hours with highest demand. The same considerations arise for other steam plants that operate at much lower capacity factors than they were planned for and justified by. Some hydro plants have also changed operating patterns from their original use, either running for more hours to maintain downstream flow or for fewer hours due to reduced water supply. Peaking capacity is used to provide a range of ancillary services at many load levels, including upward ramping services (when load surges during the day or wind and solar output falls) and operating reserves (especially to back up large generation and transmission facilities). Reflecting these considerations may require modification of the inputs to the POD analysis, which considers only current use, not historical causation.

Second, the POD method spreads the cost of each resource equally to all hours or energy output, assigning the same cost of a totally baseload plant (with a 100% capacity factor) to the lowest-load off-peak hour as to the system peak hour. That approach comports with some concepts of equity and cost responsibility: The cost of each resource is allocated

107 If this example had included a street lighting class, that class might not have been allocated any combustion turbine costs if the lights would not be on in the summer peak hours. In a more realistic example, including outages of the baseload plants, the combustion turbines probably would operate in some hours with street lighting loads and the lighting class would be allocated some combustion turbine costs.

108 In the simpler forms of POD, the costs of both plants would be spread over the top 10% of hours. In more sophisticated approaches that map generation to actual operating hours, the steam plant would generate in many hours with load lower than the top 10%, while missing some of the top 10%, due to limits on load following.

proportionately to the classes that use it. On the other hand, it can be argued that the hours with higher marginal energy costs contribute more of the rationale for investing in that resource and that, in a sense, each kWh of usage at high-load times should bear more of the resource's investment-related costs than should each kWh in the off-peak hours. This concern can be addressed by weighting the energy over the hours, such as in proportion to some measure of hourly market price.

Third, it is important that the load and dispatch data be representative of the cost causation or resource usage in the years for which the cost allocation will be in place. For example, a baseload plant may have operated at only 40% capacity factor in the most recent year because of major maintenance or availability of economic energy imports. Or load and dispatch in the last 12 months of data may be atypical because of an extremely cold winter and mild summer. The POD allocation should be based on weather-normalized dispatch and load, just as the rate case costs allowed by the regulator and included in the cost of service study should reflect weather-normalized load.

### Decomposition

Class obligations for generation costs have occasionally been addressed by dividing the generation resource into separate generation systems serving hypothetical loads for portions of the utility's customers, such as just the residential customers, just the commercial customers and just the industrial customers. For example, industrial customers in Nova Scotia have argued that their high-load-factor demands could be served by the capacity and energy of some set of baseload plants, where those costs are lower than the average generation cost per kWh (Drazen and Mikkelsen, 2013, pp. 11-16). The industrial advocates for this approach assume that the flat industrial load would be served exclusively by baseload plants and that all other costs should be allocated to other classes.[109] A similar approach might inappropriately be suggested to justify allocating the highest-cost resources to customers with behind-the-meter solar generation and lower-cost resources to nonsolar customers whose load does not dip in midday. The method might also be used to test whether classes are paying for enough capacity to cover their energy and reliability requirements.

In the context of resources stacked under a load duration curve, such as that shown in Figure 33 on Page 119, the decomposition approach allocates the resource mix horizontally, rather than the vertical allocation used in the POD method. Figure 35 on the next page illustrates the decomposition approach.

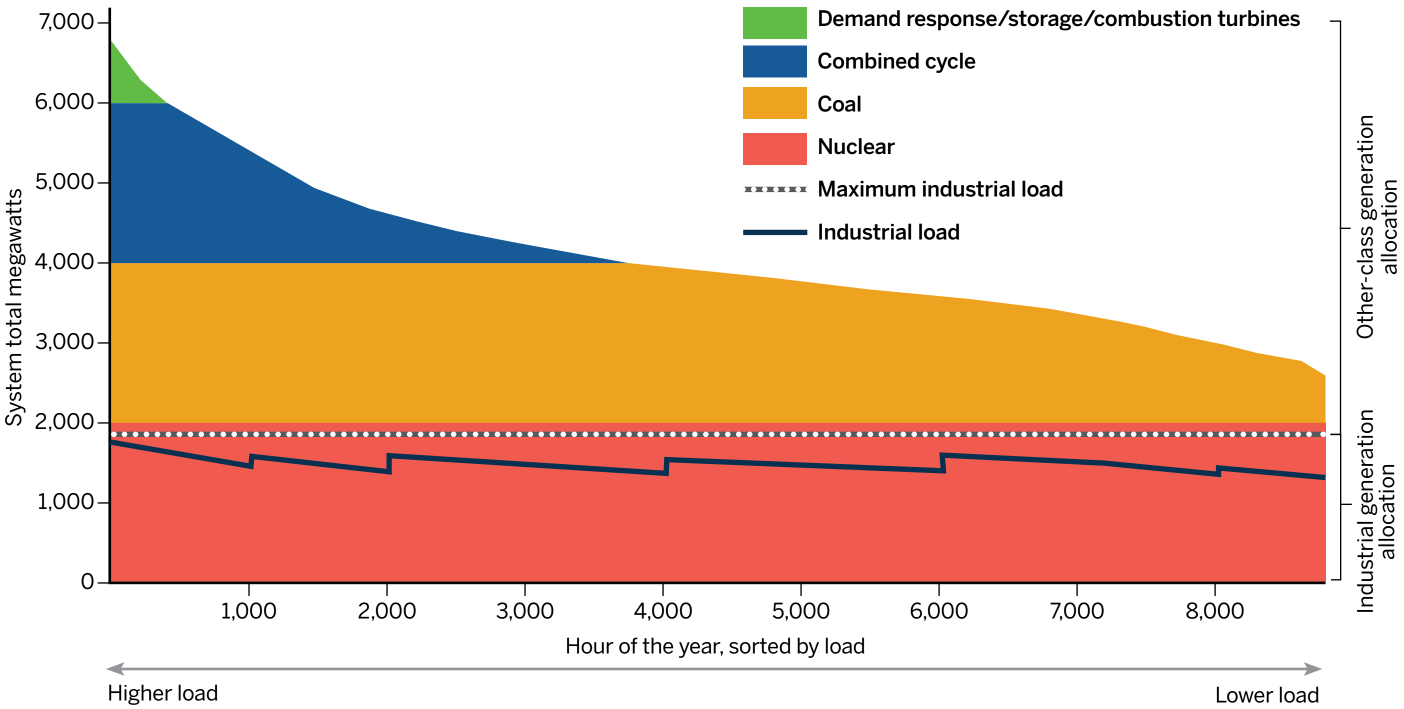
In essence, the decomposition method treats the utility as if it were multiple separate utilities. In the case of Figure 35, the utility system is decomposed into an all-nuclear system with enough capacity to meet the industrial peak load, and a utility with a little nuclear and all the other resources to serve all other load. Whether the industrial customers would support this allocation would usually depend on the cost of the nuclear resources compared with the system average.

The decomposition approach conflicts with reality in many ways, including:

1. The reserve requirements for the decomposed systems would be driven by their noncoincident class peaks or high loads (if they are assumed to be fully free-standing), requiring additional hypothetical capacity for utilities that are not already extensively overbuilt. If the decomposition assumes that the multiple class-specific systems would operate in a power pool, contribution to the system peaks would drive capacity requirements.
2. A system with a high load factor and relatively few large units would require a very high reserve margin (as discussed in Subsection 5.1.1) to cover fixed outages and even maintenance outages. The reserve units would operate in many hours (since the system load would always be near the allocated baseload capacity).
3. A baseload-only system would require a large amount of backup supply energy, either from hypothetical units or as purchases from the other classes.
4. The decomposition approach is usually designed to assign the lowest-cost resources to the industrial class,

109 A decomposition method that accounts for all relevant factors may not show an advantage for industrial customers. In Alberta, a related method to the decomposition method was presented to demonstrate that baseload power for industrial customers would be considerably more expensive than the demand-based cost allocation of the existing system for the industrial class (Marcus, 1987).

**Figure 35. Illustration of decomposition approach to allocating resource mix**




shifting all the costs of mistakes and market changes onto the other classes. That includes excess capacity (even excess baseload and capacity made excess by decline in industrial loads), the costs of fuel conversion and the high costs of plants built as baseload but currently operated as peakers.

5. It is not clear how variable renewables and other unconventional resources would be incorporated into the decomposed utility systems.

It is possible (if not certain) that the decomposition approach could be expanded and revised to create a viable classification and allocation method, but at this point no such model has been developed.

## 9.1.4 Other Technologies and Issues

Several types of generation costs do not fit neatly into the classification methods discussed in the previous sections. Some of those costs, such as hydro resources and purchased power, have been part of utility cost structures since before the development of formal cost of service studies. Others, such as excess capacity and uneconomic investments, became prominent in recent decades. More recently, utilities have needed to deal with allocating nonhydro renewable costs; a few utilities already have significant costs for nonhydro storage (mostly batteries) and most will need to deal with those costs in the future. As technologies change, new cost allocation challenges will arise — for new resources, repurposed existing assets and newly obsolete resources.

### Fuel Switching and Pollution Control Costs

Many fuel conversion investments have been undertaken to reduce fuel costs or increase the reliability of fuel supply for high-capacity-factor power plants. This category includes:

- Conversion of oil-fired steam plants to burn coal in the 1970s and 1980s (most of which have since been retired).
- Conversion of gas-fired plants to burn oil in the 1970s, when the supply of gas was limited.
- Conversion of oil-fired plants to co-firing or dual firing with gas since the 1990s to achieve environmental compliance and reduce fuel costs.
- Conversion of coal-fired plants to partial or full operation on gas to achieve environmental compliance.
- Conversion of coal-fired plants to partial or full

operation on biomass to achieve environmental compliance and RPS credit.[110]

- Conversion of coal-fired plants to partial or full operation on petroleum coke, tire-derived fuel or other waste to reduce fuel costs.

These investments and resulting longer-term operating costs may reasonably be classified as 100% energy-related.

Most pollution control retrofit costs are incurred to comply with regulatory requirements to reduce the environmental effects of fossil-fueled plants and to allow them to continue burning low-cost fuel at high capacity factors. Peaking units that are needed only in a few high-load hours annually can afford to burn expensive clean fuels and are often allowed to have higher emissions rates since they operate so little. Hence, the need for the pollution control is driven primarily by the energy-serving function of the nonpeaking fossil plants. These environmental costs are most often related to emissions standards for air pollutants, but some substantial costs are driven by the need to protect water quality and aquatic life and to meet other health and environmental standards. As a result, the identifiable capital investment and nondispatch O&M costs of pollution controls may reasonably be classified as 100% energy-related or allocated in proportion to class usage of energy during the times that the plant is operated, to recognize the causes of the environmental retrofits.[111]

## Excess Capacity and Excess Costs

Utilities sometimes add generation that is not needed to maintain adequate reliability. Some of that excess capacity may result from the lumpiness of generation additions or declining load, with no clear connection to the classification of the additional costs. Other times the excess is the result of the long lead times for certain baseload generation (especially nuclear, but also some coal and hydro facilities), which can result in a plant being completed after the need for its capacity has vanished and the value of its energy output has decreased dramatically. One or both of those outcomes befell many of the nuclear plants and some coal plants in the late 1970s and 1980s. The long lead times are generally the result of choices to build plants to produce large amounts of energy at low variable costs; in those cases, there is a reasonable presumption that the costs of the excess capacity are due to anticipated or actual energy requirements.[112]

Excess capacity can be priced at the costs of contemporaneous peaking capacity and allocated among classes in proportion to the differences between projected class contribution to peak loads (at the time commitments were undertaken) and actual current class loads. Excess capitalized energy costs (net of equivalent peaking capacity costs and any fuel savings) similarly can be allocated in proportion to the differences between class projected energy requirements and their actual energy requirements.

Table 18 on the next page provides an illustration of the allocation of excess capacity among classes to reflect responsibility for the excess. In this illustration, the actual load in the rate case test year is 600 MWs lower than the load forecast at the time the utility committed to the excess capacity. Because of other adjustments in supply planning, the utility has about 480 MWs of excess capacity, which would support about 400 MWs more load than the actual need. That 400-MW excess is allocated among the classes in proportion to their shortfalls in load.[113]

This adjusted peak load could be used in allocating peaking resources or the peaking-equivalent portion of all generation resource costs. A similar approach could be applied to allocate the additional costs of having a baseload-heavy resources mix resulting from actual energy use being lower than the forecast usage.

Another source of excess capacity is the addition of clean resources to allow the reduced use of dirty older generation, which thus allows the utility to meet environmental

110 In principle, biomass conversion might also reduce fuel costs, although that is not necessarily the case.

111 Nova Scotia Power uses this adjustment to the average-and-peak approach (Nova Scotia Power, 2013a, p. 37).

112 Accounting for a suboptimal system resource mix (and other inefficiencies) is also discussed in detail in Chapter 18.

113 Any load shortfall due to increased utility efficiency efforts since the commitment to build the capacity should generally be excluded from the shortfall.

Table 18. Allocation of 400 MWs excess capacity to reflect load risk

| | Forecast load (MWs) | Actual load (MWs) | Load differential | Share of load shortfall | Allocated excess (MWs) | Load for allocation (MWs) |
|---|---|---|---|---|---|---|
| **Residential** | 1,400 | 1,500 | +100 | 0% | 0 | 1,500 |
| **Secondary commercial** | 2,300 | 2,000 | -300 | 43% | 171 | 2,171 |
| **Primary industrial** | 2,700 | 2,300 | -400 | 57% | 229 | 2,529 |
| **Total** | 6,400 | 5,800 | +600 | 100% | 400 | 6,200 |

requirements, reduce fuel costs or meet portfolio standards.[114] Even though these new clean resources may raise the reliability of generation supply (usually above an existing adequate level), their costs were incurred as a result of energy loads; in these cases, the excess capacity should be recognized as energy-related.[115]

Aside from excess capacity, changing economic, technological and regulatory conditions can result in a facility providing a service different from its original purpose. For example, a previously baseload generation plant may run on only a few days annually or may house a distribution service center. The plant may still have unrecovered capital costs, environmental cleanup obligations or other burdens. If the full cost of the repurposed facility exceeds its value in its new use, the excess costs should be allocated based on its former use as a baseload generating plant.[116]

Finally, the amortization of a canceled generation plant is attributable to the reason the utility spent the money on the plant, long before the plant's costs and benefits were clear. Many nuclear plants were canceled after the utility spent more on the plant than the entire original expected cost, most recently the Summer plant in South Carolina. A number of coal plants were also canceled after the commitment of substantial funds.

### Hydroelectric Generation

The classification of hydroelectric generation presents some issues that differ from those of thermal generation.[117] First, many large generation facilities installed prior to 1960 are still in operation, so their costs are difficult to classify using the equivalent peaker method. Most of them could not be built today, given environmental siting constraints, so comparing new construction costs with new peaker costs may not be practical. Second, each conventional hydro facility consists of turbines and dams (and other civil works), which have different and varying effects on the energy and

114 MidAmerican Energy, for example, will have added over 6,000 MWs of wind in the period 2004-2020 to reduce fuel costs to its retail customers but has kept most of its fossil generation in operation (Hammer, 2018). This could result in a MISO-recognized reserve margin of 26% in unforced capacity terms in certain areas (Hammer, 2018, Table 3). This is nearly three times the typical MISO-required unforced capacity reserve around 8% (Midcontinent Independent System Operator, 2018, p. 23).

115 Texas and Iowa established their initial renewable portfolio standards in terms of installed capacity, rather than the more common energy percentage requirement, and several jurisdictions have established targets for specific renewables (e.g., solar, offshore wind). See Texas Utilities Code § 39.904 and Iowa Code Ch. 476 §§ 41-44. The motivations for these targets, however they are formulated, have been primarily related to reducing fuel costs and emissions. Both Texas and Iowa have exceeded their requirements and continue to add renewables to reduce fuel and other energy costs.

116 Excess costs can also be associated with underutilized or repurposed facilities. For example, a retired steam power plant may be used to warehouse distribution equipment; the generator may be operated as a synchronous condenser to support the transmission system; or a portion of the plant site may remain in service to house a combustion turbine, a transmission switching station or a control center. Sometimes this is intentionally done to avoid (or evade) a rate base disallowance for a unit retired prior to being fully depreciated. Most of those costs continue to be attributable to the original purpose of the steam plant and hence to energy and demand. Similarly, the utility may face cleanup costs for a former coal gasification site or any site contaminated by hazardous materials (e.g., heavy metals, waste lubricating oil or PCB-contaminated transformer oil). Regardless of how that site is used today or was most recently used, the cleanup costs are attributable to the activity that generated the contamination, not the current use.

117 The treatment of pumped storage, where water is pumped uphill off-peak and released to produce electricity during peak periods, is addressed with other storage technologies in Subsection 9.1.4.

demand values of the facility. Adding a turbine may increase the facility's capacity at peak load times without increasing energy output, since total energy output is limited by the amount of water flowing in the river. At another hydro facility, adding an additional turbine will not increase the output in periods of peak need (usually summer and winter) because there is not enough water to run the additional turbine, but it may increase energy output in the spring flood; this energy has value, even if it does not contribute to meeting peak load. Adding additional water storage (such as in an upstream reservoir to hold water from the spring flood) may allow the plant to operate longer hours each day but may not increase the contribution in peak hours. Increasing the height of a dam may increase capacity by raising the hydraulic head and also increase energy output because of both the greater head and the increased storage volume.

Hydro is distinct in that the fuel supply (water) is limited, and although the units usually can be dispatched to cover higher-cost hours, doing so precludes using the units at lower-cost hours. Utilities have often recognized this dual function of hydro investments by classifying hydro plant costs to both energy and capacity. For example:

- BC Hydro in British Columbia classifies hydro generation as 45% energy-related (BC Hydro, 2014, p. 9).
- Newfoundland and Labrador Hydro has proposed classification of 80% energy for a new hydro project (Newfoundland and Labrador Hydro, 2018, p. 6).
- Manitoba Hydro has long classified its generation as 100% energy-related, but this was modified in 2016 to an average-and-peak classification approach with a broad peak demand allocation measure (Manitoba Public Utility Board, 2016, pp. 47-53).

Other utilities, including Idaho Power, Hydro-Québec, and Newfoundland and Labrador Hydro, use the average-and-peak approach for legacy hydro.

In selecting classification and allocation methods it is important to recognize the usage of each type of hydro resource. Some are run-of-river, with each hour's output determined by the amount of water flowing through the system. Other hydro resources have limited flexibility in dispatch due to environmental constraints. Both of these categories of hydro resources should be treated as variable, similar to wind and solar.

Other categories of hydro resources have some storage capacity, allowing the operator to optimize dispatch over a day, a week or even a year.[118] These resources are generally operated under a reliability-constrained economic dispatch regime, but since the variable cost is zero or minimal, they are dispatched to maximize the value of their limited energy supply rather than in merit dispatch order. For example, a hydro resource may be able to generate 100 MWhs in the hour ending at 2 a.m. at no cost, but the dispatcher is likely to prefer to keep the water in the reservoirs to be used for operating reserves, load following and avoidance of fuel costs in higher-cost hours later in the day.

The difference between the dispatch of hydro and thermal resources requires some adaptation in classification and allocation approaches. In some applications of the BIP classification approach, for example, resources are stacked under the load duration curve starting with the resources with the lowest variable costs. In a system with a significant hydro contribution, the method must be modified to reflect the value (not cost) in time periods (ideally hours) in which hydro energy is actually provided, whether that is due to run-of-river, minimum flow or economic dispatch.

It may be appropriate to recognize that some hydro resources are justified primarily by avoiding fuel costs in high-load hours, resulting in allocation of the investment-related hydro costs in proportion to some measure of hourly market or marginal energy costs.[119]

118 Many of these resources will also operate with little or no flexibility in the spring flood, with minimum flow constraints (which may change by season) and with requirements for flow variation for streambed maintenance, recreational activities, flood control and other factors.

119 Many hydro resources bear the costs of providing services unrelated to electric generation, such as flood control, recreation, water supply and environmental protection. Other resources, especially those built in recent decades, may also bear the costs of endangered species protection, conservation easements, access to open space, aesthetic screening around a plant or payments in lieu of taxes. If the non-energy benefits are conditions of a license or permit, those are simply the costs of building or running the plant.

### Renewable Energy

Renewable energy, generated from wind, solar, biomass, hydro, geothermal and other technologies, is becoming a larger part of the electric supply mix and hence the cost allocation challenge. Renewable resources may have very different cost characteristics than conventional resources, and the decision to invest in them may be driven by policy that may not consider peak demand at all.

As discussed in Subsection 7.1.2, renewable energy may be added — even though the utility does not need the capacity at peak hours — to reduce fuel costs, comply with portfolio requirements (which often require that a specified percentage of energy consumption is supplied by renewable generation) or meet environmental targets, particularly reducing the atmospheric effects of fossil energy generation. This substitution of capital investment for fuel is widely accepted as an important approach in 21st century utility planning, as shown in examples from Colorado, Iowa and Indiana.[120]

In the classification of costs between capacity and energy, renewable costs that are driven by energy consumption, either directly or indirectly, should be classified as energy-related. For renewable resources that provide some demand-related benefits, the costs can be classified between demand and energy based on the equivalent peaker, average-and-peak or other methods, as long as the demand-related portion is discounted to reflect the effective load-carrying capacity of the renewable resource. Variable renewable resources fit well in a time-based allocation (such as a detailed POD allocation) because their costs can be allocated directly to the hours in which they provide energy to the system.

### Purchased Power

Many power purchase agreements with utilities or non-utility generators (especially fossil-fueled generation) have been structured with two types of charges: predetermined monthly charges the utility must pay regardless of how much energy it takes from the power producer, as long as the supplier meets contracted requirements for availability; and variable charges per MWh that the buyer pays for the energy it takes. The charges may reflect the projected cost of a single unit or plant (traditionally fossil fueled, increasingly renewable) at the time the contract was signed, or the actual cost of service for a unit or a portfolio of resources.

Another large set of power purchase agreements — including PURPA contracts, some dating back to the 1980s, and most 21st century renewable projects — pay the provider a rate per kWh delivered (perhaps with different rates by time of delivery). This cost structure fits well into an hourly allocation framework, although it is also possible to extract a demand component of the resource's value for inclusion in a traditional demand/energy framework.

Many utilities classify the monthly guaranteed portion of payments to independent power producers as demand-related, using the archaic perspective that any generation cost that is committed for the rate year should be considered fixed and therefore demand-related, thus leading to great controversy in choosing the appropriate basis for allocation of demand-related costs. In reality, the utility may have agreed to the payment structure because of the low-cost energy provided by the deal, with that financial commitment having value to the resource owner in obtaining financing.

Others classify purchased power to mimic the classification of generation plant, as if the purchase were the equivalent of plant capital, without fuel.[121] This treatment is similarly inconsistent with cost causation. Many power purchase agreements are structured to recover the costs of a baseload or intermediate resource, such as by charging a relatively high nonbypassable capacity charge and a low energy charge based on the usage of the resource. These contracts are typically not the lowest-cost way to meet peak loads. The only rational reason to enter into these contracts

120 Xcel Energy touted its renewable energy investments as "steel for fuel," in which "capital recovery costs [are] offset by lower fuel and O&M costs" and wind "displaces coal and natural gas fuel," resulting in "significant customer savings" (2018). MidAmerican Energy justified its aggressive wind generation plan on eliminating exposure to fossil fuel costs (Hammer, 2018). Northern Indiana Public Service Co. found that replacing its coal plants' fuel and operating costs with wind and solar would reduce customer costs, uncertainty and risk (2018, p. 6).

121 The contract may require the purchaser to take all of the available energy, so even a rate denominated in MWhs can be thought of as investment-related and thus similar to generation plant costs. In reality, the purchase contract replaces both the investment-related and variable costs of a comparable resource built by the purchasing utility.

would be to access lower-priced energy and higher efficiency. The classification process should look beyond the contract pricing terms to ascertain the true cost causation factors and where the benefits accrue.

Within the centrally dispatched power pools (such as the New England, New York, California and Midcontinent ISOs), utilities and other load-serving entities purchase energy on an hourly basis to meet their loads. The transactions are priced at the marginal costs of the supply bids to the system operator and cover some investment-related costs for most generators. The cost of those purchases should be classified as energy and allocated to loads on a time-differentiated basis.[122]

Costs for purchased power can be classified in most of the same ways that the costs of utility-owned generation are classified, including the probability-of-dispatch, equivalent peaker and average-and-peak methods and many others. In many cases, the purchase will be from a specific plant whose investment and nondispatch O&M costs can be allocated in the same manner as the costs of similar resources the utility owns. In other cases, such as system power, the classification and allocation of power purchase costs will need to be based on the cost characteristics of the purchase.[123] Where possible, the most straightforward classification approach would be to treat as energy-related the excess of the purchase costs over the capacity costs of a contemporaneous gas turbine peaking plant.

## Energy Storage

Energy storage takes many forms, including:

- Water held in conventional hydro reservoirs.
- Pumped storage hydro facilities.
- A variety of battery technologies, which may be co-located with generation, transmission or distribution facilities or be behind the customer's meter.
- A host of other electricity storage technologies, including compressed air, flywheels and gravity (moving weights upward to store energy, using the potential energy to drive a generator as needed).
- Thermal storage as molten salt in solar thermal plants, ice or hot water at customer premises.

Batteries will be an increasingly important part of utility systems, and therefore of cost allocation studies, because of their flexibility and the rapid and continuing decline in their costs. Batteries can be installed (1) at the location of generation to stabilize or optimize output to the transmission system; (2) at substations to avoid transmission and distribution costs; or (3) throughout the system, on the utility or customer side of the meter to avoid transmission and distribution costs and to provide customer emergency power.

Batteries can provide a range of services, including contributing to bulk supply reliability, ancillary services (load following, reserves and automatic generator control), energy arbitrage, transmission load relief, distribution load relief and customer emergency supply. To the extent that the allocation study can reflect these various services, it should classify the costs of the batteries in proportion to their value. That classification may be based on the frequency with which the storage is used for each purpose, on the anticipated mix of benefits that justified the installation, or on the incremental cost incurred to achieve the additional purpose.[124] Batteries may be very valuable for providing second-contingency support to the transmission system (avoiding the installation of redundant equipment), even if they may never actually be dispatched for that purpose. Where utilities purchase some attributes of behind-the meter batteries, such as ancillary services, the services they purchase should drive the cost allocation.

Storage operates as both a load and a supply resource and thus may operate at very different times than conventional generation. As a result, storage fits well into hourly allocation

122 Some utilities in these pools own generation, which is sold into the regional market. The revenue from those sales can be credited against the costs of the generator before those costs are allocated to classes.

123 Since costs for purchased power may be recovered through both base rates and a power cost recovery mechanism, and the allocation of these costs may be reflected in both base rates and the power-cost mechanism, some care should be taken to ensure that the allocation is applied only once, just as the costs are recovered only once. For example, the costs for purchased power may be included in the cost of service study, with the anticipated purchased-power revenues from each class subtracted from the allocated costs. Alternatively, the purchase costs may be excluded from the base rate cost of service study and allocated separately on an appropriate basis in the fuel and purchased power cost recovery mechanism.

124 Renewable incentives and tax policy may encourage co-location of storage with centralized renewable generation. Moving the storage to support transmission, distribution or customer resilience would typically increase both the value and the cost of the resource; those incremental costs should be classified as due to the incremental service.

schemes. Storage usually delivers power into the grid at high-cost hours, so assigning the capital and operating costs, including the costs of charging storage, to those hours usually will result in an equitable tracking of costs to benefits.

But storage also provides some services while it is charging, including operating reserves. A 200-MW pumped storage unit can typically transition from being a 200-MW pumping load to a 200-MW supply within minutes, providing 400 MWs of net operating reserves at no incremental cost during low-cost hours, allowing avoidance of fuel costs for load-following resources. Storage may also provide other ancillary services while charging. If the cost of service study is sophisticated enough to classify and allocate ancillary services separately from demand and energy, some of the storage costs can be classified to ancillary service, reflecting the increased reserves available during charging.

In addition, some utility systems experience high ramp rates in net load at times that variable renewable generation is declining and load is rising, such as an evening-peaking utility with a large amount of solar generation in the midday period. To be able to ramp up output from other generation quickly enough to offset the drop in renewable output and meet the rising load, the system may require the construction of additional resources and the uneconomic operation of thermal generators at low-load times to ensure they are available when the ramping need arises. Storage-charging load in the period of minimum net load (which is also likely to be a period of low or even negative short-run marginal costs) raises the minimum load and reduces the ramp rate. These benefits flow to the loads during the ramping period, not just during the discharge period, so some of the costs of storage should be allocated to those loads.

#### System Control and Dispatch

The costs of scheduling, committing and dispatching generation units, recorded in FERC Account 556, are fixed in the short term but vary with the generation mix, load shapes and variability and other considerations. Costs of forecasting load and supply and optimizing dispatch may vary depending on the amount of weather-related load, the existence of large loads and large generators that may suddenly trip off line, the extent of integration with other utilities, the length of time required for major plants to start up and the amount of variable renewable generation. Some dispatch costs would be required, even if the utility only needed to dispatch generation on a few peak hours, while others are required for multiday planning, 24-hour operation and other energy-related factors.

These costs might most reasonably be classified as partly demand-related and partly energy-related. Reasonable approaches would include classification of dispatch costs in proportion to the classification of long-term generation costs, using the average-and-peak method or a 50/50 split between energy and demand.

### 9.1.5 Summary of Generation Classification Options

Table 19 on the next page summarizes some attributes of the generation classification options described above. These descriptions are highly simplified and should be read in context of the discussion prior, including the discussion of special situations in Subsection 9.1.4.

## 9.2 Allocating Energy-Related Generation Costs

Energy-classified generation costs are often allocated to all classes in proportion to total annual class energy consumption. Alternatively, energy-related costs can be calculated by time period and allocated to classes in proportion to their usage in each time period. Assigning costs to time periods is usually straightforward for fuel and dispatch O&M.[125] For systems with high penetration of variable renewables, such as wind and solar, then TOU or BIP allocation of energy-related costs is the most equitable.

The energy-related capital investment and nondispatch O&M costs can be allocated to classes in proportion to

125 One possible complication with time differentiation is that some steam plants must be operated in low-load hours, when they are not really needed, so that they will be available when needed in higher-load hours. The costs of fuel and reagents used in low-load hours may be required to serve high-load hours, but the plants may also be supplying energy in the low-load hours; sorting out generation and fuel use among periods within a week or day can be very complicated.

**Table 19. Attributes of generation classification options**

| Method | Data and computational intensity | Accuracy of cost causality | Allows joint classification/ allocation | Applicability |
|---|---|---|---|---|
| **Straight fixed/variable** | Very low | Very low | No | Peaker-only systems |
| **Competitive proxy** | Low | Medium | No | In or near regional transmission organizations that perform revenue computations |
| **Average and peak** | Low | Low | No | Hydro systems |
| **Simple base-intermediate-peak** | Low to medium | Medium | No | Simple systems: limited hydro, solar, wind, storage |
| **Complex base-intermediate-peak** | High | High | Yes | Broad |
| **Equivalent peaker (peak credit)** | Low | High | No | Broad |
| **Operational characteristics (capacity value, capacity factor, operating factor)** | Generally low | Low to medium | No | Limited |
| **Probability of dispatch** | Medium to high | Highest | Yes | Broad |
| **Decomposition** | Very high | Low | Yes | Rarely |

energy or assigned among time periods in proportion to the fuel and dispatch O&M. Table 20 provides an illustration of the development of energy-classified costs per MWh (both dispatch- and investment-related) over three time periods.

Table 21 on the next page shows an illustrative example applying these costs per MWh to usage for three customer classes by time period to allocate costs.

The comparable computation for most utilities could use many more periods (perhaps even hourly data), include all resource types and compute usage by generation unit, rather than category.

Manitoba Hydro, which has an almost all-hydro system, assigns energy-classified capital investment costs among four seasons and three time periods (for a total of 12 periods) in proportion to the MISO market prices for exports in those periods, reflecting the reality that there are hours in which

**Table 20. Illustrative example of energy-classified cost per MWh by time of use**

| | Energy-related cost per MWh | Capacity (MWs) | Period (and annual hours): Peak (50) | Midpeak (2,000) | Off-peak (6,710) | Total |
|---|---|---|---|---|---|---|
| **Resource type** | | | | | | |
| Nuclear | $30 | 500 | $750,000 | $28,500,000 | $90,585,000 | $119,835,000 |
| Coal | $40 | 1,500 | $3,000,000 | $84,000,000 | $161,040,000 | $248,040,000 |
| Combined cycle | $35 | 1,000 | $1,750,000 | $35,000,000 | $0 | $36,750,000 |
| Peaking | $100 | 300 | $1,500,000 | $12,000,000 | $0 | $13,500,000 |
| Demand response | $250 | 100 | $1,250,000 | $0 | $0 | $1,250,000 |
| Subtotal of all resources | | | $8,250,000 | $159,500,000 | $251,625,000 | $419,375,000 |
| **Consumption (MWhs)** | | | 170,000 | 4,170,000 | 7,045,500 | 11,385,500 |
| **Cost per MWh** | | | $48.53 | $38.25 | $35.71 | $36.83 |

Note: Numbers may not add up to total because of rounding. The illustration assumes that all resources are fully utilized in the peak period, with reductions in capacity factor between periods by 5 percentage points for nuclear, 30 points for coal, 50 points for combined cycle and 80 for peaking.

Table 21. Illustrative example of time-of-use allocation of energy-classified costs

| | Period (and annual hours) | | | |
|---|---|---|---|---|
| | Peak (50) | Midpeak (2,000) | Off-peak (6,710) | Total |
| **Consumption (MWhs)** | 170,000 | 4,170,000 | 7,045,500 | 11,385,500 |
| **Cost per MWh** | $48.53 | $38.25 | $35.71 | $36.83 |
| **Class** | | | | |
| **Residential** | | | | |
| Consumption (MWhs) | 69,250 | 2,080,000 | 2,818,200 | 4,967,450 |
| Allocated costs | $3,360,662 | $79,558,753 | $100,650,000 | $183,569,415 |
| **Commercial** | | | | |
| Consumption (MWhs) | 85,000 | 1,460,000 | 2,113,650 | 3,658,650 |
| Allocated costs | $4,125,000 | $55,844,125 | $75,487,500 | $135,456,625 |
| **Industrial** | | | | |
| Consumption (MWhs) | 15,750 | 630,000 | 2,113,650 | 2,759,400 |
| Allocated costs | $764,338 | $24,097,122 | $75,487,500 | $100,348,961 |

Note: Numbers may not add up to total because of rounding.

transmission constraints preclude additional exports. That approach recognizes that using energy in some time periods is more expensive for Manitoba Hydro (in terms of lost export revenues) than consumption in other time periods.

## 9.3 Allocating Demand-Related Generation Costs

As discussed in Subsection 9.1.3, some classification methodologies, such as probability of dispatch and more granular hourly variants, simultaneously develop cost by period and the associated allocation factors driven by use by period. This section describes methods for developing allocation factors for demand-related costs developed by legacy demand/energy classification methods.

Typically, utilities allocate demand-related generation based on some form of class contribution to system peak loads, referred to as coincident peak. The loads that determine how much capacity a utility requires may be concentrated in a few hours a year, a few hours in each month, the highest 50 or 100 hours in the year, or some other measure of the loads stressing system reliability.

Frequently used demand allocators include:

- The class contributions to the annual system coincident peak (1 CP).
- The class contributions to three or four seasonal peaks (3 CP or 4 CP).
- The average of the class contributions to multiple high-load hours, such as:
  - The 12 monthly peaks (12 CP).
  - All hours with loads greater than a threshold, such as 80% to 95% of annual peak.
  - **Peak capacity allocation factor** (PCAF), a technique developed in California that weights high-usage hours based on how close each hour is to the peak hour.
  - Hours with some expectation for loss of energy.
  - Hours in which the system is stressed (e.g., operating reserves are below target levels).

As discussed in Chapter 5, generation capacity requirements have always been driven by more than a few hourly loads. Moreover, with peak loads being offset by solar generation and expanding demand response available to serve the highest-load or highest-cost hours, capacity requirements are driven by an even broader group of hours, which should be reflected in the development of the demand allocation factors. Broader allocation factors also have the virtue of limiting the instability resulting from the use of a limited number of peak hours. For example, ERCOT experienced an annual peak in 2017 at approximately

69,500 MWs on July 28 at 5 p.m. However, there were 13 other hours within 2% of that annual peak in 2017, in the hours ending at 3 p.m. to 7 p.m. (Electric Reliability Council of Texas, 2018, and calculations by the authors). Changes in temperature or cloud cover could shift the peak load to any of those hours. The peak timing in the load data can be very important in determining the allocators. The residential class typically will have a greater share of a peak load occurring at 7 p.m. than one occurring at 3 p.m. or 4 p.m.[126]

Utilities have sometimes allocated generation demand costs on the class NCP at the system level.[127] This approach may have been roughly appropriate for some utilities serving distinct classes with peak demands in different seasons, such as winter-peaking ski resorts and summer-peaking irrigation pumping, with both seasons contributing to the need for generation capacity. The class NCP would not recognize whatever load the ski resorts' summer operations contribute to the pumping-dominated peaks and would allocate demand costs to other classes based on their summer or winter peaks — but not their contributions to either of the seasons' high-load hours. Since reliability computations and the need for generation capacity are driven by combined system load, some measure of the combined loads on the system is relevant. With the hourly data collection technologies now available, this class NCP approximation is no longer necessary.

Traditionally, without access to the kind of sophisticated hourly data we can obtain today, utilities have tended to allocate demand costs on a single annual coincident peak, the average of the four monthly peaks in the high-load summer season, the average of some number of summer and winter monthly peaks, a defined number of peak hours when peaking resources are expected to operate, or the average of the 12 monthly peaks.[128] The number of months included in the computations of the demand allocator often reflects the following factors:

- The number of months in which the system may experience its annual peak load.
- Whether high loads occur in both summer and the winter.
- Whether requirements for maintenance outages reduce available capacity in off-peak months enough that available reserves in those months are comparable to the reserves in the peak months.

A more comprehensive approach to these factors would develop the demand allocator from all the hours identified in a loss-of-energy expectation study, after accounting for maintenance scheduling. Depending on the system, that may be several hours or several hundred hours. If data are not available for a comprehensive loss-of-energy expectation analysis, a demand allocator based on all hours within a specified percentage of the peak (e.g., 80% to 95%) or based on a significant number of the highest hours in the year (e.g., 100) is preferable to a coincident peak analysis. In sum, averaging or weighting a small number of coincident peaks incorrectly assumes that the need for capacity is a simple function of the amount of the system monthly peak, even though capacity requirements are driven by many hours,

126 The range of loads in these 14 hours was only about 1,400 MWs, roughly the size of one large nuclear unit or two large coal units. The differences in loads over those hours are of little significance in terms of reliability.

127 In some jurisdictions, the class NCP is referred to as the maximum class peak, maximum diversified demand or something similar, and "NCP" is used to designate the sum of the individual customer noncoincident peaks within each class. We refer to class NCP and customer NCP in this manual to distinguish between the two methods.

128 FERC has a set of guidelines for determining whether wholesale demand-classified costs should be allocated on 3 CPs or 12 CPs (for example, see Federal Energy Regulatory Commission, 2008, pp. 30-35). FERC's approach does not contemplate that any other number of months (such as four or eight) might be responsible for the need for capacity.

Table 22. Attributes of generation demand allocation options

| Method | Data and computational intensity | Accuracy of cost causality | Allows joint classification/ allocation | Applicability |
|---|---|---|---|---|
| **1 CP** | Very low | Very low | No | Rare |
| **3 CP; 4 CP** | Low | Low | No | One-season peak; needle peaks |
| **12 CP** | Low | Low to medium | No | Multiple seasonal peaks; extensive maintenance requirements; class load shapes near peak similar |
| **Multiple hours near peak (e.g., top 100 hours)** | Low to medium | Medium | No | Broad, but loss-of-energy expectation gives more robust results if data exist to calculate them |
| **Loss-of-energy expectation** | High | High | No | Broad |
| **Complex base-intermediate-peak** | High | High | Yes | Broad |
| **Probability of dispatch** | Medium to high | High | Yes | Broad |

depending on load; the amount of generation capacity that is available, not just installed; and the scheduling of maintenance outages.

Table 22 summarizes some characteristics of the allocation methods described in this section, along with the POD method described in Subsection 9.1.3 and the more complex variants of the BIP method from Subsection 9.1.2.

## 9.4 Summary of Generation Allocation Methods and Illustrative Examples

As demonstrated in many ways in the previous sections, it is appropriate to classify some of the long-term investment and O&M costs to energy usage rather than to demand. Table 23 presents a simplified view of appropriate classification results by plant type.

As variable renewable capacity (mostly wind and solar) on a system increases, the role for baseload capacity decreases. At some point, in hours with low load and high renewable output, traditional baseload resources will run only if they cannot shut down and restart on a timely basis.

Cost of service studies can also combine features of the various classification approaches, such as classifying peakers as 100% demand-related; classifying fuel conversion costs, environmental costs and generation without firm transmission as 100% energy-related; and applying the average-and-peak

Table 23. Summary of conceptual generation classification by technology

| Resource type | Function | Classification |
|---|---|---|
| **Nuclear, some hydro and best coal** | Baseload | Primarily energy |
| **Modern combined cycle, best gas-fired steam and mediocre coal** | Intermediate | Energy and demand |
| **Combustion turbines, mediocre fossil-fueled steam and combined cycle** | Peaking and operating reserves | Primarily demand or on-peak energy |
| **Storage and flexible hydro** | Peaking and energy shifting | Demand or on-peak energy |
| **Wind and solar** | Energy and some capacity | Primarily energy |

Note: "Best" refers to resources with the lowest variable costs, "mediocre" to those with higher variable costs. Resources that are worse than mediocre are likely candidates for retirement. "Intermediate" refers to generation that is neither baseload nor peaking.

**Table 24. Summary of generation allocation approaches**

| Resource type | Classification and allocation methods: Legacy | Modern | Evolving |
|---|---|---|---|
| **Nuclear** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: 12 CP | CLASSIFICATION: Equivalent peaker<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: Loss-of-energy expectation | All hours |
| **Baseload coal** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: 12 CP | Probability of dispatch | Hours dispatched |
| **Combined cycle** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: 12 CP | Probability of dispatch | Hours dispatched or used for reserve |
| **Gas-fired steam** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: On-peak energy<br>DEMAND ALLOCATOR: 4 CP* | Probability of dispatch | Hours dispatched or used for reserve |
| **Peaker** | CLASSIFICATION: 100% demand<br>DEMAND ALLOCATOR: 4 CP or 12 CP | Probability of dispatch | Hours dispatched or used for reserve |
| **Hydro** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: 12 CP* | Probability of dispatch | Hours dispatched or used for reserve |
| **Wind** | CLASSIFICATION: 100% energy<br>ENERGY ALLOCATOR: All energy | CLASSIFICATION: Equivalent peaker<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: Loss-of-energy expectation | Hours of output |
| **Solar** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: On-peak energy<br>DEMAND ALLOCATOR: 4 CP | CLASSIFICATION: Equivalent peaker<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: Loss-of-energy expectation | Hours of output |
| **Storage** | CLASSIFICATION: Average and peak<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: 12 CP | Probability of dispatch | Hours dispatched, used for reserve or reducing ramp rate |
| **Demand response** | CLASSIFICATION: 100% demand<br>DEMAND ALLOCATOR: 3 CP to 12 CP** | CLASSIFICATION: 100% demand<br>DEMAND ALLOCATOR: 3 CP to 12 CP** | Hours dispatched or used for reserve |

* Depends on use of resource
** Depends on program type and technology

approach to the remaining costs. A hybrid approach is only as equitable as the component techniques but may be useful where particular classification decisions can be made before the application of a generic approach to the residual costs.

Table 24 summarizes examples of allocation factors that might be applied to the capital and nondispatch O&M costs for various types of generation resources, whether utility-owned or purchased.[129] This summary is, by its very nature, highly simplified, ignoring many of the complexities discussed in sections 9.1, 9.2 and 9.3.

129 The probability-of- dispatch and hourly approaches can also be applied to the short-run variable costs of the resources.

For simplicity, we show an illustration only for generation investment-related costs. Table 25 shows the amount of investment in each category, which we will then divide using multiple allocation methods.

Table 26 shows two currently used methods: a legacy 1 CP system measure and a more modern method, equivalent peaker, where 80% of baseload costs are considered to be energy-related. The illustrative load data and allocation factors are from tables 5 through 7 in Chapter 5.

Table 27 shows the calculation of an hourly allocation model, where baseload costs are apportioned to all hours, peaking and intermediate costs to midpeak hours, and storage only to the 2% of usage at the most extreme hours.

**Table 25. Illustrative annual generation data**

| | Net generation (MWhs) | Annual nonfuel revenue requirement | Annual nonfuel cost per MWh |
|---|---|---|---|
| **Baseload** | 1,860,000 | $74,400,000 | $40 |
| **Peaker** | 534,000 | $42,720,000 | $80 |
| **Solar** | 1,056,000 | $31,680,000 | $30 |
| **Storage** | 62,000 | $6,200,000 | $100 |
| **Total** | 3,512,000 | $155,000,000 | $44 |
| | Disposition of net generation | | |
| **Storage input and delivery losses** | 412,000 | | |
| **Sales to customers** | 3,100,000 | | |

Note: Numbers may not add up to total because of rounding.

**Table 26. Allocation of generation capacity costs by traditional methods**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **1 CP (legacy)** | $51,667,000 | $62,000,000 | $41,333,000 | $0 | $155,000,000 |
| **Equivalent peaker** | $50,333,000 | $52,400,000 | $47,750,000 | $4,517,000 | $155,000,000 |

Note: Numbers may not add up to total because of rounding.

**Table 27. Modern hourly allocation of generation capacity costs**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **Baseload (all hours)** | $24,000,000 | $24,000,000 | $24,000,000 | $2,400,000 | $74,400,000 |
| **Peaker (midpeak)** | $14,424,000 | $15,735,000 | $12,326,000 | $236,000 | $42,720,000 |
| **Solar (daytime)** | $10,560,000 | $12,320,000 | $8,800,000 | $0 | $31,680,000 |
| **Storage (critical peak)** | $2,366,000 | $2,366,000 | $1,420,000 | $47,000 | $6,200,000 |
| **Total hourly allocation** | $51,350,000 | $54,421,000 | $46,545,000 | $2,683,000 | $155,000,000 |
| **Composite hourly factor** | 33% | 35% | 30% | 2% | 100% |

Note: Numbers may not add up to total because of rounding.

# 10. Transmission in Embedded Cost of Service Studies

As discussed in Chapter 3, investments in transmission lines and substations are needed and valuable for a wide assortment of purposes, including integrating inherently remote generation, allowing economic dispatch of generation over large areas and providing backup reliability. Any particular transmission line and the substations to which it is connected may perform multiple functions under varying load and generation conditions. Because the purposes for constructing transmission and the use of the facilities vary so widely, the allocation methods used may need to distinguish among several categories of transmission.

The generation-related portions of transmission equipment — including switching stations, substations and transmission lines required to tie generators into the general transmission network and reinforcements of the transmission system required by remote generation locations and by economic dispatch — are often functionalized as generation.

In regions with FERC-regulated ISOs or RTOs, state regulators may not have authority to determine the amount of bulk transmission cost a local distribution utility must pay. The states may choose to allocate costs among classes in a manner similar to that FERC uses to allocate costs among utilities and other parties. States also retain the authority to allocate that cost using a different method than FERC uses for wholesale market allocation.

## 10.1 Subfunctionalizing Transmission

As noted in Chapter 3, transmission of different voltage levels often serves similar functions. Nonetheless, some utilities have subfunctionalized transmission between **extra-high-voltage** (EHV) facilities (perhaps over 100 kV) and subtransmission (at lower voltages), sometimes called network transmission as it connects the different substations inside the utility service territory. Subtransmission that FERC does not claim authority over (based on voltage, configuration, direction of power flow and other factors) is regulated by the state or consumer-owned utility governing body.

If those subfunctions were classified and allocated in the same manner, the division of the facilities by voltages would not matter. Unfortunately, some cost of service studies allocate only the EHV facilities to certain customers directly served from these facilities, with customers served at subtransmission or distribution voltages being charged for both the EHV system and the subtransmission. For example, in 2013, Nova Scotia Power proposed to functionalize 23% of transmission costs to subtransmission and excuse from those costs the largest industrial customers, served at 138 kV (Nova Scotia Power, 2013b). Similarly, Manitoba Hydro functionalizes its 66-kV and 33-kV transmission lines as subtransmission, which is allocated to all classes except for the industrial customers served at voltages above 66 kV (Manitoba Public Utility Board, 2016).

This approach is inequitable and fails to reflect cost causality. The various voltages of transmission serve complementary functions. In general, customers and distribution substations that are served from subtransmission would be more expensive to serve from EHV transmission. Subtransmission is a lower-cost alternative to EHV where the higher capacity of the EHV facilities is not required.

For some systems, the subtransmission and EHV systems may seem to be serving different functions since the EHV lines may be more often networked or looped, while the subtransmission lines are often radial. This pattern is due to the higher load-carrying capacity of the EHV lines, which results in their being used in high-load backbone configurations. These lines are usually networked for greater reliability, not due to some inherent difference in the capabilities of the technologies. Higher-voltage lines can be used in radial applications, and subtransmission can be networked or looped in some situations.

Figure 36 is a section of a California transmission map, showing EHV lines as solid lines (220 to 287 kV) and large dashed lines (110 to 161 kV) and subtransmission as small dashed lines (California Energy Commission, 2014). This excerpt shows some features that are consistent with the proposition that higher-voltage transmission is networked while subtransmission is radial:

- A large backbone transmission line running north-south.
- A looped network of 110- to 161-kV lines coming off the backbone line into the Oakland area.
- Radial subtransmission lines that dead-end at distribution substations in Berkeley and parts of Oakland.

But Figure 36 also illustrates situations contradicting these stereotypes:

- Networked subtransmission lines in the San Leandro-San Lorenzo area.
- Radial 220- to 287-kV lines that dead-end at such substations as Rossmoor and Castro Valley.

**Figure 36. Transmission east of San Francisco Bay**


Source: California Energy Commission. (2014). *California Transmission Lines – Substations Enlargement Maps*

Thus, the idea that the EHV system is a network and the subtransmission system is a purely radial system served off the EHV network is a gross simplification. If loads to near San Lorenzo were higher, for example, the local utility might have upgraded the subtransmission network to higher voltages.

As a result, the separation of subtransmission is often inappropriate in principle and impractical in application, leading to the conclusion that all voltages of transmission should be allocated consistently as a single function.

However, if a state determines that subtransmission costs are to be allocated to the classes that use the subtransmission system, ignoring the complementary nature of high- and low-voltage transmission, the allocator should approximate the extent to which each class uses the subtransmission system and not be designed simply as a benefit to high-voltage industrial customers.

Not all distribution loads are served from subtransmission. If industrial customers served directly off the EHV system are excused from being allocated a share of the subtransmission, so should the portion of distribution load served by substations that are fed from EHV transmission. Although segregating EHV facilities is typically performed in a manner that benefits a small number of EHV industrial customers, a full subfunctionalization of transmission for all classes would sometimes reduce the allocation to classes served at distribution, at the expense of the classes served directly from the subtransmission system.

A separate subtransmission allocator should approximate the following:

- An EHV industrial class that takes all its power from the EHV system would be allocated no subtransmission costs.
- A subtransmission industrial class that takes all its power from the subtransmission system would be allocated subtransmission costs in proportion to its entire load.
- A general transmission class would be allocated subtransmission costs in proportion to the fraction of its load served from subtransmission.
- The distribution classes would be allocated subtransmission costs in proportion to the fraction of their load served from substations on the subtransmission lines.

Most large utilities appear to serve a significant fraction of distribution load from the EHV system. The utility FERC Form 1 reports indicate that at least 26% of Southern California Edison's distribution substation capacity (the substations with low-side transformers below 30 kV) is served from the EHV system; for Northern Indiana Public Service, the portion is at least 49% (Federal Energy Regulatory Commission, n.d.).[130]

## 10.2 Classification

The classification of transmission costs raises many of the same issues as the classification of generation costs and can often be dealt with in similar ways. As for generation, some approaches for transmission avoid the need for classification by assigning specific transmission facilities to the loads occurring in the hours in which these lines serve customers with improved reliability, lower variable costs or other benefits.

Some assets that are carried on the books as transmission may actually be related to interconnecting or integrating generation (step-up transformers and generation ties for many utilities; more extensive facilities for utilities with extremely remote generators). Those facilities can either be functionalized as generation-related and classified along with the generation resource or functionalized as transmission and classified in the same manner as the investment-related costs of the associated generation. Facilities connecting peakers should be treated as demand-related, while those connecting the baseload generation, especially remote generation, should be primarily treated as energy-related since the facilities were built primarily to provide energy benefits. For example, Manitoba Hydro classifies as entirely energy-related the high-voltage direct current system that brings its northern hydro generation to the southern load centers and export points, as well as its transmission interties, which allow for economic energy exports and for off-peak energy imports to firm up hydro supplies in drought conditions.[131]

In addition to the substations that step up the generator output to transmission voltages and the lines that connect the generator to the broader transmission network, many utilities have transmission facilities that are integrated with the transmission network but are driven largely by the need to move large amounts of power from remote generators. Those transmission facilities may be identifiable because they were originally required to reinforce the transmission system when major baseload (or remote hydro or wind) resources were added or because they connect areas that have surplus generation to areas with generation shortages. For example, a utility may have 60% of its load in a central metropolitan area but 80% of its baseload resources far to the east or north, with multiple major transmission lines connecting the resource-rich east with the load in the center.[132]

130 Some distribution substation transformers are at substations serving multiple transmission voltages. The FERC Form 1 reports provide only the total transformer capacity at the substation, without differentiating among the EHV-subtransmission, EHV-distribution and EHV-EHV capacity. The percentages of distribution capacity served from the EHV system, listed above, do not include any of this multivoltage capacity.

131 The northern AC gathering system that brings the hydro to the HVDC converters is also classified as energy-related.

132 Examples of this phenomenon include Nova Scotia Power's concentration of coal in the eastern end of the province; BC Hydro's, Manitoba Hydro's and Hydro-Quebec's northern generation; PacifiCorp's Rocky Mountain Power division (with load concentrated around Salt Lake City and generation in Colorado, Wyoming, Arizona and Montana); Arizona Public Service Co. with load in Phoenix and generation in the Four Corners and Palo Verde areas; Puget Sound Energy and the Colstrip transmission system from Montana; the California utilities and the AC and DC interties to the Pacific Northwest and lines to the Southwest; and Texas' concentration of wind generation in the Panhandle, serving load throughout ERCOT. This pattern is also emerging for California's imports of solar energy from Nevada and Arizona, Minnesota's imports of wind power from North Dakota and hydro energy from Manitoba, and the transfers of large amounts of wind power from generation in the western parts of Kansas and Oklahoma to load centers in the eastern parts of those states.

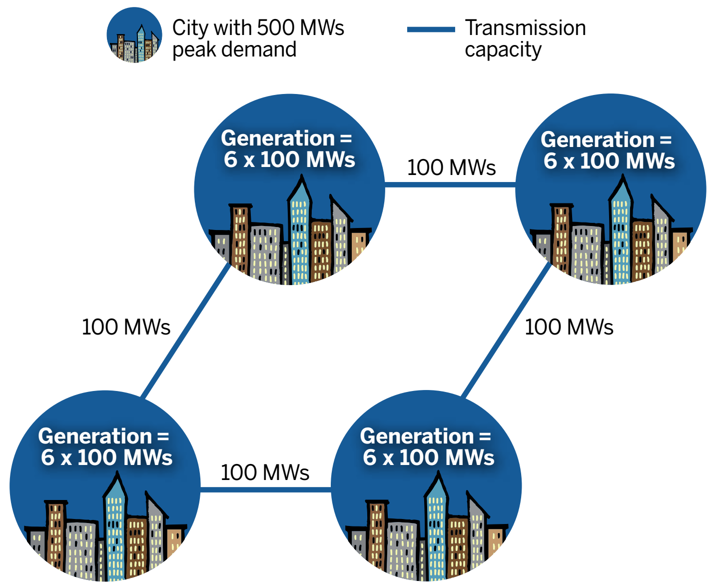
Utility transmission system design typically lowers energy costs in at least three ways. First, a large portion of many transmission systems is required to move power from the remote generators to the load centers and for export. If generation were located nearer the load centers, the long, expensive transmission lines would not be required, and transmission losses would be smaller. These transmission costs were incurred as part of the trade-off against the higher operating costs of plants that could be located nearer the load centers — in other words, as a trade-off against energy-related costs. This category includes transmission built to allow the addition of remote wind resources, which are often the least-cost energy resources even where the utility already has sufficient capacity and energy supply. In other cases, the remote wind resources may be more expensive than conventional resources, new or existing, but less expensive than local renewables (e.g., solar, wind turbines in areas with lower wind speed, higher land costs and more complex siting problems) that would otherwise need to be built to comply with energy-related renewable energy standards.

Second, transmission systems are more expensive because they are designed to allow for large transfers of energy between neighboring utilities. Third, transmission systems are designed to minimize energy losses and to function over extended hours of high loading. Were the system designed only to meet peak demands, a less costly system would suffice; in some cases, entire lines or circuits would not be required, voltage levels could be lower, and fewer or smaller substations would be needed.

Figure 37 shows a simple illustrative system with relatively small units of a single generation resource co-located with each load center. Since all the generators are the same, economic dispatch does not require shipping power from one load center to another, so transmission is limited to the amount needed to allow reserve capacity in one center to back up multiple outages in another center. In this simple illustration, the transmission costs would truly be demand-related.

Figure 38 on the next page illustrates a more complex system, with baseload coal concentrated in one area, combined cycle generation in another and combustion turbines in a third. Additional transmission corridors and substations are required to connect remote generation (wind from one direction and hydro from another), and the transmission lines between the load centers need to be beefed up to support backup of the larger units and the economic dispatch of the lowest-cost available generation to meet load. In this more complex system, the incremental costs of transmission (compared with the simple system in Figure 37) should be classified as energy-related.

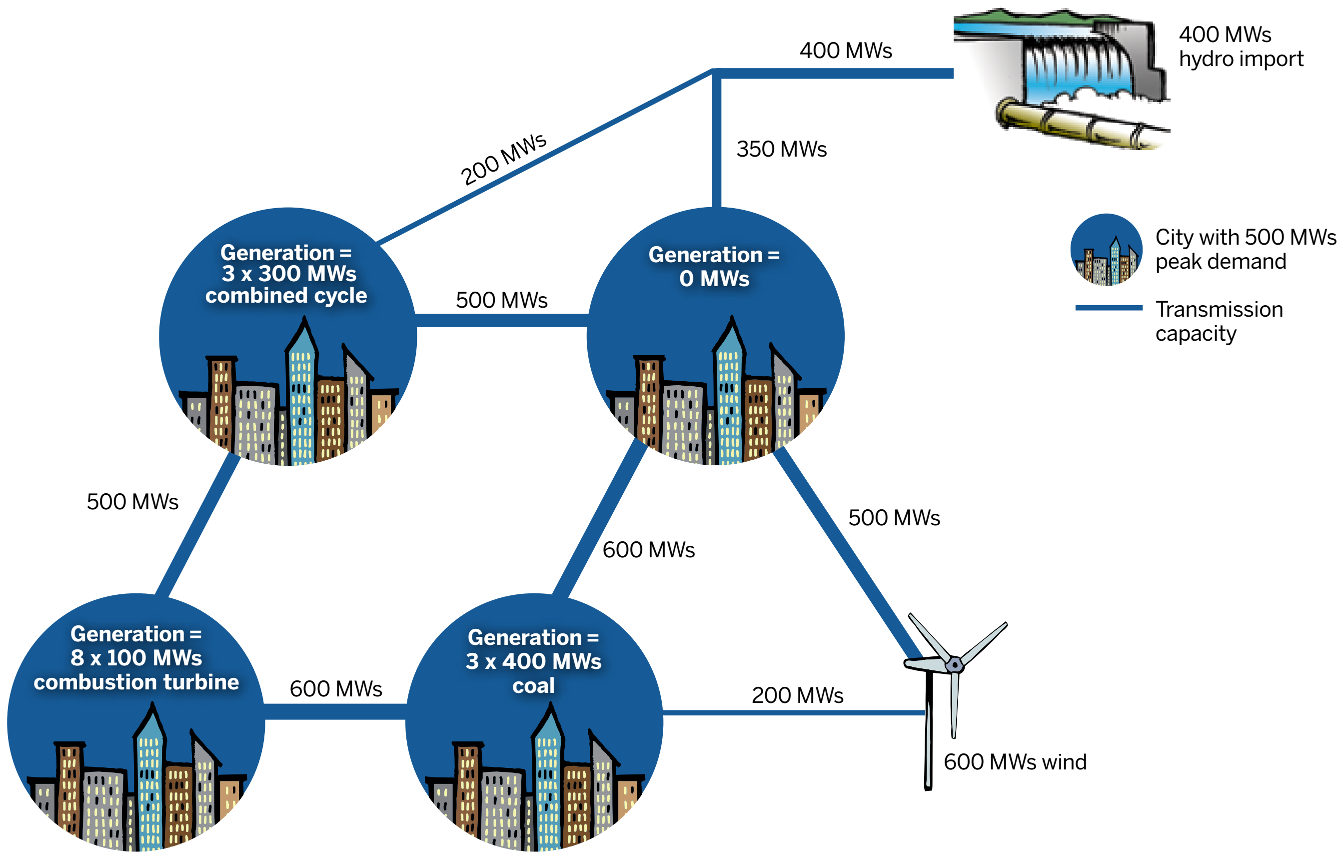
**Figure 37. Transmission system with uniformly distributed demand and generation**




It may be possible to identify and classify the costs of the individual lines or classify total costs in proportion to circuit-miles of each voltage serving various energy functions. If all else fails, a more judgment-based classification method, such as average and peak, may be the best feasible option.

PacifiCorp's Rocky Mountain Power subsidiary in Utah classifies transmission as 75% demand-related and 25% energy-related (Steward, 2014, p. 7). This classification recognizes that, although peak loads are a major driver of transmission costs, a significant portion of transmission costs is incurred to reduce energy costs. Since PacifiCorp has a large amount of transmission connecting remote coal plants in Wyoming, Arizona and Colorado to its load centers and connecting its Northwestern hydro assets to its load centers, an even higher energy classification may be

Figure 38. Transmission system with remote and centralized generation




appropriate. PacifiCorp's highest-voltage lines (500 kV, 345 kV and 230 kV) primarily connect its load with remote baseload generation and would not be needed except to access low-cost energy. Those lines account for more than half of PacifiCorp's transmission investment. Hence, more than half of PacifiCorp's transmission revenue requirement is likely to be attributable to energy.

Similarly, Nova Scotia Power has much of its generation (coal plants, storage hydro and an HVDC import of hydropower from Newfoundland) in the eastern end of the province, but most of its load is about 250 miles to the west. To reflect the large contribution of remote generation to its transmission cost, the company uses an average-and-peak (system load factor) approach that effectively classifies about 62% to energy and 38% to demand (Nova Scotia Utility and Review Board, 2014, pp. 22-23).

Washington state has explicitly rejected a single hour of peak as a determinant and ruled that transmission costs should be classified to both energy and demand (Washington Utilities and Transportation Commission, 1981, p. 23). Appropriate classification percentages will vary among utilities and transmission owners.

## 10.3 Allocation Factors

Historically, most cost of service studies have computed transmission allocation factors from some combination of monthly peak demands from 1 CP to 12 CP.

Some utilities have recognized that transmission investments are justified by loads in more than one hour in a month. For example, Manitoba Hydro has used a transmission allocator computed from class contribution to the highest 50 hours in the winter, Manitoba Hydro's peak period, and the highest 50 hours in the summer, the period of Manitoba Hydro's maximum exports, which also drive intraprovincial transmission construction (Manitoba Hydro, 2015, Appendix 3.1, p. 9).

The hours of maximum transmission loads may be different from the hours of maximum generation stress. For example, the power lines from remote baseload units to the load centers may be most heavily loaded at moderate demand levels. At high load levels, more of the low-cost remote generation may be used by load closer to the generator, while higher-cost generation in and near the load centers increases, reducing the long-distance transmission line loading. In addition, generator maintenance does not necessarily smooth out transmission reliability risk across months in the same way that it spreads generation shortage risk. If transmission loads peak in winter, when carrying capacity is higher, then transmission peaks may not match even the maximum transmission stress period.

In its Order 1000, establishing regional transmission planning and cost allocation principles, FERC includes the following cost allocation principles, which recognize that transmission is justified by multiple drivers and that different allocation approaches may be justified for different types of transmission facilities:

> (1) The cost of transmission facilities must be allocated to those ... that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs. ...
>
> (5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.
>
> (6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief or to achieve public policy requirements established by state or federal laws or regulations (Federal Energy Regulatory Commission, 2011, ¶ 586).

The FERC guidance clearly anticipates differential treatment of transmission facilities built for different purposes. Aligning costs with benefits may require allocation of transmission costs to most or all hours in which a transmission facility provides service.[133]

Demand-related transmission costs may be allocated to hours in proportion to the usage of the lines or to the high-load hours in which transmission capacity may be tight following a contingency (the failure of some part of the system) or two. The high-load hours may be chosen as a more or less arbitrary number of the highest hours, as in Manitoba, or as the hours in which loads on a particular line or substation are high enough that the worst-case planning contingency (such as the loss of two lines) would leave the transmission system with no more reserve than it has on the system peak with no contingencies.[134]

## 10.4 Summary of Transmission Allocation Methods and Illustrative Examples

The discussion above has indicated why transmission investments must be carefully scrutinized in the cost allocation process. Different transmission facilities provide different services and are thus appropriately allocated by different allocation methods. Table 28 on the next page lists some types of transmission facilities and identifies appropriate methods for each.

Transmission is a very difficult challenge for the cost analyst because each transmission segment may have a

133 Attributing transmission to hours is more complicated than assigning generation costs by hours, because of the flow of electricity in a network. Once a transmission line is in service, power will flow over it any time there is a voltage differential between the ends of the line, whether or not the line was in any way needed to meet load in that hour.

134 The latter definition would require load flow modeling for each transmission line or a representative sample; the practicality of this approach will depend on the extent of transmission modeling undertaken for system planning.

**Table 28. Summary of transmission classification and allocation approaches**

| Element | Example methods | Comments | Hourly allocation |
|---|---|---|---|
| **Bulk transmission** | CLASSIFICATION: To energy* — costs to allow centralized generation and economic dispatch; cost due to heating<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: Highest 100 hours | • Typically above 150 kV<br>• Mostly bidirectional<br>• Operates in all hours | Allocate in proportion to usage or hours needed |
| **Integration of remote generation** | CLASSIFICATION: To energy* — costs to connect remote energy resources<br>ENERGY ALLOCATOR: All energy<br>DEMAND ALLOCATOR: Highest 100 hours | Treat same as connected remote resources | Allocate in same manner as remote resources |
| **Economy interconnections** | CLASSIFICATION: Energy and demand | Depends on purpose and use of connection | • Allocate reliability value as equivalent peaker<br>• Allocate energy value in proportion to use |
| **Local network** | CLASSIFICATION: To energy* — cost due to heating<br>ENERGY ALLOCATOR: On-peak energy<br>DEMAND ALLOCATOR: 4 CP to 12 CP | • Typically below 150 kV<br>• Mostly radial | Allocate in proportion to usage or hours needed |
| **Transmission substations** | As lines** | May also have distribution functions | As lines** |

* "To energy" = portion classified as energy-related
** "As lines" = in proportion to the classification or allocation of the lines served by each substation

different history and purpose and that purpose may have changed over time. For example, a line originally built to connect a baseload generating unit that has since been retired is repurposed to facilitate economic energy interchange with nearby utilities. In Table 29, we use only three methods, which may or may not be relevant to particular types of transmission costs, including purchased transmission service from another utility, a transmission-owning entity or an ISO. The illustrative data for the 1 CP and equivalent peaker methods are from tables 5 through 7 in Chapter 5, and the hourly allocation factor is derived in Table 27 in Chapter 9.

**Table 29. Illustrative allocation of transmission costs by different methods**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **1 CP (legacy)** | $16,667,000 | $20,000,000 | $13,333,000 | $0 | $50,000,000 |
| **Equivalent peaker** | $16,237,000 | $16,903,000 | $15,403,000 | $1,457,000 | $50,000,000 |
| **Hourly** | $16,565,000 | $17,555,000 | $15,015,000 | $866,000 | $50,000,000 |

Note: Numbers may not add up to total because of rounding.

# 11. Distribution in Embedded Cost of Service Studies

Distribution costs are all incurred to deliver energy to customers and are primarily investment-related costs that do not vary in response to load in the short term. Different rate analysts approach these costs in very different ways. These costs are often divided into two categories.

1. Shared distribution, which typically includes at least:
    - Distribution substations, both those that step power down from transmission voltages to distribution voltages and those that step it down from a higher distribution voltage (such as 25 kV) to a lower voltage (such as 12 kV).
    - Primary feeders, which run from the substations to other substations and to customer premises, including the conductors, supports (poles and underground conduit) and various control and monitoring equipment.
    - Most line transformers, which step the primary voltage down to secondary voltages (under 600 V, and mostly in the 120 V and 240 V ranges) for use by customers.
    - A large portion of the secondary distribution lines, which run from the line transformers to customer service lines or drops.
    - The supervisory control and data acquisition equipment that monitors the system operation and records system data. This is a network of sensors, communication devices, computers, software and typically a central control center.
2. Customer-specific costs, which include:
    - Service drops connecting a customer (or multiple customers in a building) to the common distribution system (a primary line, a line transformer or a secondary line or network).
    - Meters, which measure each customer's energy use by month, TOU period or hour and sometimes by maximum demand in the month.[135] Advanced meters can also provide other capabilities, including measurement of voltage, remote sensing of outages, and remote connection and disconnection.[136]
    - Street lighting and signal equipment, which usually can be directly assigned to the corresponding rate classes.
    - In some systems with low customer spatial density, a significant portion of primary lines and transformers serving only one customer.

## 11.1 Subfunctionalizing Distribution Costs

One important issue in cost allocation is the determination of the portion of distribution cost that is related to primary service (the costs of which are allocated to all customers, except those served at transmission voltage) as opposed to secondary service (the costs of which are borne solely by the secondary voltage customers — residential, some C&I customers, street lighting, etc.).

Some plant accounts and associated expenses are easily subfunctionalized. Substations (which are all primary equipment) have their own FERC accounts (plant accounts 360 to 362, expense accounts 582 and 592). In addition, distribution substations take power from transmission lines and feed it into the distribution system at primary voltage. All distribution substations deliver only primary power and therefore should be subfunctionalized as 100% primary.

135 The Uniform System of Accounts treats meters as distribution plant and the costs of keeping the meters operable as distribution expenses, even though all other metering and billing costs are treated as customer accounts or A&G plant or expenses. Traditional meters that tally only customer usage are not really necessary for the operation of the distribution system, only for the billing function. As a result, references to meters in this chapter are quite limited, and the costs of meters are discussed with meter reading and billing in the next chapter.

136 These capabilities require additional supporting technology, some of which is also required to provide remote meter reading. These costs should be spread among a variety of functions, including distribution and retail services, as discussed in Section 11.5.

However, many other types of distribution investments pose more difficult questions. The FERC accounts do not differentiate lines, poles or conduit between primary and secondary equipment, and many utilities do not keep records of distribution plant cost by voltage level. This means any subfunctionalization requires some sort of special analysis, such as the review of the cost makeup of distribution in areas constituting a representative sample of the system.

Traditionally, most cost of service studies have functionalized a portion of distribution poles as secondary plant, to be allocated only to classes taking service at secondary voltage. This approach is based on misconceptions regarding the joint and complementary nature of various types of poles. Although distribution poles come in all sorts of sizes and configurations, the important distinction for functionalization is what sorts of lines the poles carry: only primary, both primary and secondary or only secondary. The proper functionalization of the first category — poles that carry only primary lines — is not controversial; they are required for all distribution load, the sum of load served at primary and the load for which power is subsequently stepped down to secondary.[137]

For the second category — poles carrying both primary and secondary lines — some cost of service studies have treated a portion of the pole cost as being due to all distribution load and the remainder as being due to secondary loads, to be allocated only to classes served at secondary voltage. There is no cost basis for allocating any appreciable portion of these joint poles to secondary. The incremental pole cost for adding secondary lines to a pole carrying primary is generally negligible. The height of the pole is determined by the voltage of the primary circuits it carries, the number of primary phases and circuits and the local topography. Much of the equipment on the poles (cross arms, insulators, switches and other monitoring and control equipment) is used only for the primary lines. The required strength of the pole (determined by the diameter and material) is determined by the weight of the lines and equipment and by the leverage exerted by that weight (which increases with the height of the equipment and the breadth of the cross arms, again due to primary lines).[138] Equipment used in holding secondary lines has a very low cost compared with those used for primary lines. If the poles currently used for both secondary and primary lines had been designed without secondary lines, the reduction in costs would be very small. Thus, the costs of the joint poles are essentially all due to primary distribution.

Although nearly all poles carry primary lines, a utility sometimes will use a pole just to carry secondary lines, such as to reach from the last transformer on a street to the last house, or to carry a secondary line across a wide road to serve a few customers on the far side. Secondary-only poles are usually shorter and skinnier and thus less expensive than primary poles and do not require cross arms and other primary equipment. Some cost of service studies functionalize a portion of pole costs to secondary, based on the population of secondary-only poles (either from an actual inventory or an estimate) or of short poles (less than 35 feet, for example), on the theory that these short poles must carry secondary.

The assumption that all short poles carry secondary is not correct; some utility poles carry no conductor but rather are stubs used to counterbalance the stresses on heavily loaded (mostly primary) poles, as illustrated in Figure 39 on the next page. Depending on the nature of the distribution system and the utility's design standards, the number of stub poles may rival the number of secondary-only poles.

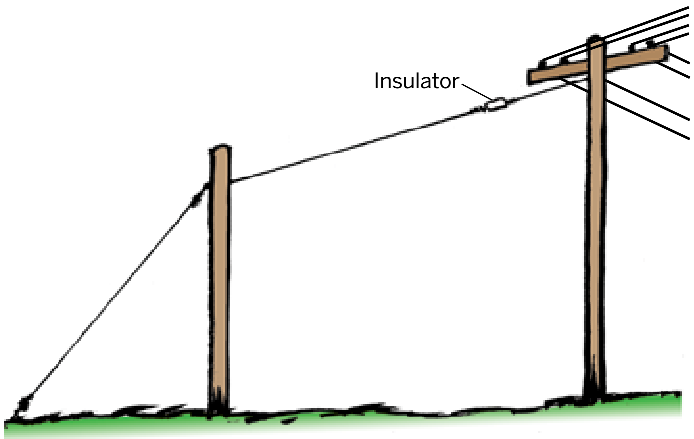
Where only secondary lines are needed, the utility typically saves on pole costs due to the customer taking secondary service, rather than requiring primary voltage service and a bigger pole. Some kind of pole would be needed in that location regardless of the voltage level of service. Hence, the primary customers are better off paying for their share of the secondary poles than if the customers using those poles were to require primary service. It does not seem fair to penalize customers served at secondary for the fact that the utility is able to serve some of them using a type of pole that is less expensive than the poles required for primary service.

As a result, the vast majority of pole costs (other than for

137 The class loads should be measured at primary voltage, including losses, which will be higher for power metered at secondary.

138 There is one situation in which secondary distribution can add to the cost of poles. A very large pole-mounted transformer (perhaps over 75 kVA) may require a stronger pole, which would be a secondary distribution cost. A highly detailed analysis of pole subfunctionalization might thus result in a portion of the cost of those few poles being treated as an extra cost of secondary service, offset to some extent by the savings from some poles being designed to carry only secondary lines.

**Figure 39. Stub pole used to guy a primary pole**




dedicated poles directly assigned to street lighting or similar services) generally should be treated as serving all distribution customers.[139] For many cost of service studies, that would result in the costs being subfunctionalized as primary distribution, which is then allocated to classes in proportion to their contribution to demand at the primary voltage level.

Line transformers dominate two FERC accounts (plant account 368 and expense account 595), but those accounts also include the costs of capacitors and voltage regulators. These three types of equipment should be subfunctionalized in three different manners:

- Secondary line transformers (which compose the bulk of these accounts) are needed only for customers served at secondary voltage and thus can be subfunctionalized as 100% secondary.
- Voltage regulators are devices on the primary system that adjust voltage levels along the feeder to keep delivered voltage within the design range. The number and capacity of voltage regulators is determined by the distribution of load along the feeder, regardless of whether that load is served at primary or secondary. The regulator costs should be subfunctionalized as primary distribution and classified in the same manner as substations and primary conductors.
- Capacitors improve the power factor on distribution lines at primary voltage, thus reducing line losses (reducing generation, transmission and distribution costs), reducing voltage drop (avoiding the need for larger and additional primary conductors) and increasing primary distribution line capacity. Capacitors can be functionalized as some mix of generation, transmission and primary distribution; in any case they should be functionalized separately from line transformers.

Overhead and underground conductors as well as conduit must be subfunctionalized between primary and secondary using special studies of the composition of the utility's distribution system, since secondary conductors are mostly incremental to primary lines. Estimates of the percentage of these investments that are secondary equipment typically range from 20% to 40%.

Within the primary conductor category, utilities use three-phase feeders for areas with high loads and single-phase (or occasionally two-phase) feeders in areas with lower loads. The additional phases (and hence additional conductors) are due to load levels and the use of equipment that specifically requires three-phase supply (such as some large motors), which is one reason that primary distribution is overwhelmingly load-related and should be so treated in classification.

Some utilities subfunctionalize single- and three-phase conductors, treating the single-phase lines as incremental to the three-phase lines (see, for example, Peppin, 2013, pp. 25-26). Classes that use a lot of single-phase lines are allocated both the average cost of the three-phase lines and the average cost of the single-phase lines. This treatment of single-phase service as being more expensive than three-phase service gets it backward. If load of a single-phase customer or area changed in a manner that required three-phase service, the utility's costs would increase; if anything, classes disproportionally served with single-phase primary should be assigned lower costs than those requiring three-phase service. The classification of primary conductor as load-related will allocate more of the three-phase costs to the classes whose loads require that equipment.

139 As noted above, some utilities may be able to attribute some upgrades in pole class to line transformers; that increment is appropriately functionalized to secondary service. On the other hand, the secondary classes may be due a small credit to reflect the fact that they allow the use of some less expensive poles.

## 11.2 Distribution Classification

Newly evolving methods can fairly allocate a substantial portion of distribution costs on an energy basis.

The classification of distribution infrastructure has been one of the most controversial elements of utility cost allocation for more than a half-century. Bonbright devoted an entire section to a discussion of why none of the methods then commonly used was defensible (1961, pp. 347-368). In any case, traditional methods have divided up distribution costs as either demand-related or customer-related, but newly evolving methods can fairly allocate a substantial portion of these costs on an energy basis.

Distribution equipment can be usefully divided into three groups:

- Shared distribution plant, in which each item serves multiple customers, including substations and almost all spans of primary lines.
- Customer-related distribution plant that serves only one customer, particularly traditional meters used solely for billing.
- A group of equipment that may serve one customer in some cases or many customers in others, including transformers, secondary lines and service drops.

The basic customer method for classification counts only customer-specific plant as customer-related and the entire shared distribution network as demand- or energy-related. For relatively dense service territories, in cities and suburbs, this would be only the traditional meter and a portion of service drop costs.[140] For very thinly settled territories, particularly rural cooperatives, customer-specific plant may include some portion of transformer costs and the percentage of the primary system that consists of line extensions to individual customers. Many jurisdictions have mandated or accepted the basic customer classification approach, sometimes including a portion of transformers in the customer cost. These jurisdictions include Arkansas,[141] California,[142] Colorado,[143] Illinois,[144] Iowa,[145] Massachusetts,[146] Texas[147] and Washington.[148]

The basic customer method for classification is by far the most equitable solution for the vast majority of utilities.

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140 Alternatively, all service drops may be treated as customer-related and the sharing of service drops can be reflected in the allocation factor. As discussed in Section 5.2, treating multifamily housing as a separate class facilitates crediting those customers with the savings from shared service drops, among other factors.

141 The Arkansas Public Service Commission found that "accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and … that [large industrial consumer parties] do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes" (2013, p. 126).

142 California classifies all lines (accounts 364 through 367) as demand-related for the calculation of marginal costs, while classifying transformers (Account 368) as customer-related with different costs per customer for each customer class, reflecting the demands of the various classes.

143 In 2018, the state utility commission affirmed a decision by an administrative law judge that rejected the **zero-intercept approach** and classified FERC accounts 364 through 368 as 100% demand-related (Colorado Public Utilities Commission, 2018, p. 16).

144 "As it has in the past, … the [Illinois Commerce] Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic" (Illinois Commerce Commission, 2008, p. 208).

145 According to 199 Iowa Administrative Code 20.10(2)e, "customer cost component estimates or allocations shall include only costs of the distribution system from and including transformers, meters and associated customer service expenses." This means that all of accounts 364 through 367 are demand-related. Under this provision, the Iowa Utilities Board classifies the cost of 10 kVA per transformer as customer-related but reduces the cost that is assigned to residential and small commercial customers to reflect the sharing of transformers by multiple customers.

146 "Plant items classified as customer costs included only meters, a portion of services, street lighting plant, and a portion of labor-related general plant" (La Capra, 1992, p. 15). See also Gorman, 2018, pp. 13-15.

147 Texas has explicitly adopted the basic customer approach for the purposes of rate design: "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service" (Public Utility Commission of Texas, 2000, pp. 5-6). But it has followed this rule in practice for cost allocation as well.

148 "The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals" (Washington Utilities and Transportation Commission, 1993, p. 11).

For certain rural utilities, this may be reasonable under the conceptual view that the size of distribution components (e.g., the diameter of conductors or the capacity of transformers) is load-related, but the number and length of some types of equipment is customer-related. In some rural service territories, the basic customer cost may require nearly a mile of distribution line along the public way as essentially an extended service drop.

However, more general attempts by utilities to include a far greater portion of shared distribution system costs as customer-related are frequently unfair and wholly unjustified. These methods include straight fixed/variable approaches where all distribution costs are treated as customer-related (analogous to the misuse of the concept of fixed costs in classifying generation discussed in Section 9.1) and the more nuanced minimum system and zero-intercept approaches included in the 1992 NARUC cost allocation manual.

The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.

1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number.[149] Bonbright found that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system." He concluded that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems ... clearly indefensible. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground" (1961, p. 348).
2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers.[150] Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage duration).

149 As noted above, for some rural utilities, particularly cooperatives that extend distribution without requiring that the extension be profitable, a portion of the distribution system may effectively be customer-specific.

150 Adding transformers also reduces the length of the secondary lines from the transformers to the customers, reducing losses, voltage drop or the required gauge of the secondary lines.

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.
4. The "minimum system" would still meet a large portion of the average residential customer's demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system (Sterzinger, 1981, pp. 30-32).
5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted.[151] However, the transformer industry could produce truly minimum-sized utility transformers, the size of those used for cellular telephone chargers, if there were a demand for these.
6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.
7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.
8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with **contributions in aid of construction**, as discussed in Section 15.2. Factoring in the entire length of the system, including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines.

Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid

151 For example, in many cases, utilities that make an allocation based on a minimum system use 10-kVA transformers, even though they installed 3-kVA or 5-kVA transformers in the past. Some utilities also have used conductor sizes and costs significantly higher than the actual minimum conductor size and cost on their systems.

overhead distribution equipment only under several unusual circumstances.[152] These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility, particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

The related zero-intercept method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load. The zero-intercept method usually involves statistical regression analysis to decompose the costs of distribution equipment into customer-related costs and costs that vary with load or size of the equipment, although some utilities use labor installation costs with no equipment. The idea is that this procedure identifies the amount of equipment required to connect existing customers that is not load-related (a zero-kVA transformer, a zero-**ampere** conductor or a pole that is zero feet high). The zero-intercept regression analysis is so abstract that it can produce a wide range of results, which vary depending on arcane statistical methods and the choice of types of equipment to include or exclude from an equation. As a result, the zero-intercept method is even less realistic than the minimum system method.

The best practice is to determine customer-related costs using the basic customer method, then use more advanced techniques to split the remainder of shared distribution system costs as energy-related and demand-related. Energy use, especially in high-load hours and in off-peak hours on high-load days, affects distribution investment and outage costs in the following ways:

- The fundamental reason for building distribution systems is to deliver energy to customers, not simply to connect them to the grid.
- The number and extent of overloads determines the life of the insulation on lines and in transformers (in both substations and line transformers) and hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.
- All energy in high-load hours, and even all hours on high-load days, adds to heat buildup and results in sagging overhead lines, which often defines the thermal limit on lines; aging of insulation in underground lines and transformers; and a reduction the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (marginal line losses due to another kWh of load greatly exceed the average loss percentage in that hour, and losses at peak loads dramatically exceed average losses).[153] To the extent that a utility converts a distribution line from single-phase to three-phase, selects a larger conductor or increases primary voltage to reduce losses, the costs are primarily energy-related.
- Customers with a remote need for power only a few hours per year, such as construction sites or temporary businesses like Christmas tree lots, will often find non-utility solutions to be more economical. But when those same types of loads are located along existing distribution lines, they typically connect to utility service if the utility's **connection charges** are reasonable.

A portion of distribution costs can thus be classified to energy, or the demand allocation factor can be modified to reflect energy effects.

The average-and-peak method, discussed in Section 9.1 in the context of generation classification, is commonly used by natural gas utilities to classify distribution mains and other shared distribution plant.[154] This approach recognizes that a portion of shared distribution would be needed even if all

152 These circumstances are: (1) if the customer would have been the farthest one from the transformer along a span of secondary conductor that is not a service drop; (2) if the customer is the only one served off the last pole at the end of a radial primary feeder, a pole and a span of secondary, or a span of primary and a transformer; and (3) if several poles are required solely for that customer.

153 For a detailed analysis of the measurement and valuation of marginal line losses, see Lazar and Baldwin (2011).

154 See *Gas Distribution Rate Design Manual* from the National Association of Regulatory Utility Commissioners (1989, pp. 27-28) as well as more recent orders from the Minnesota Public Utilities Commission describing the range of states that use basic customer and average-and-peak methods for natural gas cost allocation (2016, pp. 53-54) and the Michigan Public Service Commission affirming the usage of the average-and-peak method (2017, pp. 113-114).

customers used power at a 100% load factor, while other costs are incurred to upsize the system to meet local peak demands. The same approach may have a place in electric distribution system classification and allocation, with something over half the basic infrastructure (poles, conductors, conduit and transformers) classified to energy to reflect the importance of energy use in justifying system coverage and the remainder to demand to reflect the higher cost of sizing equipment to serve a load that isn't uniform.

Nearly every electric utility has a line extension policy that dictates the circumstances under which the utility or a new customer must pay for an extension of service. Most of these provide only a very small investment by the utility in shared facilities such as circuits, if expected customer usage is very small, but much larger utility investment for large added load. Various utilities compute the allowance for line extensions in different ways, which are usually a variant of one of the following approaches:

- The credit equals a multiple of revenue. For example, Otter Tail Power Co. in Minnesota will invest up to three times the expected annual revenue, with the customer bearing any excess (Otter Tail Power Co., 2017, Section 5.04). Xcel Energy's Minnesota subsidiary uses 3.5 times expected annual revenue for nonresidential customers (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Other utilities base their credits on expected nonfuel revenue or the distribution portion of the tariff; on different periods of revenue; and on either simple total revenue or present value of revenue.[155] These are clearly usage-related allowances that, in turn, determine how much cost for distribution circuits is reflected in the utility revenue requirement. Applying this logic, all shared distribution plant should thus be classified as usage-related, and none of the shared distribution system should be customer-related.
- The credit is the actual extension cost, capped at a fixed value. For example, Minnesota Power pays up to $850 for the cost of extending lines, charges $12 per foot for costs over $850 and charges actual costs for extensions over 1,000 feet (Minnesota Power, 2013, p. 6). Xcel Energy's Colorado subsidiary gives on-site construction allowances of $1,659 for residential customers, $2,486 for small commercial, $735 per kW for other secondary nonresidential and $680 per kW for primary customers (Public Service Company of Colorado, 2018, Sheet R226). The company describes these allowances as "based on two and three-quarters (2.75) times estimated annual non-fuel revenue" — a simplified version of the revenue approach.[156]
- The credit is determined by distance. Xcel Energy's Minnesota subsidiary includes the first 100 feet of line extension for a residential customer into rate base, with the customer bearing the cost for any excess length (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Green Mountain Power applies a credit equal to the cost of 100 feet of overhead service drop but no costs for poles or other equipment (Green Mountain Power, 2016, Sheet 148). The portion of the line extensions paid by the utility might be thought of as customer-related, with some caveats. First, the amount of the distribution system that was built out under this provision is almost certainly much less than 100 feet times the number of residential customers. Second, these allowances are often determined as a function of expected revenue, as in the Xcel Colorado example, and thus are usage-related.

If the line extension investment is tied to revenue (and most revenue is associated with usage-related costs, such as fuel, purchased power, generation, transmission and substations), then the resulting investment should be classified and allocated on a usage basis. The cost of service study should ensure that the costs customers prepay are netted out (including not just the costs but the footage of lines or excess costs of poles and transformers if a minimum system method is used) before classifying any distribution costs as customer-related.

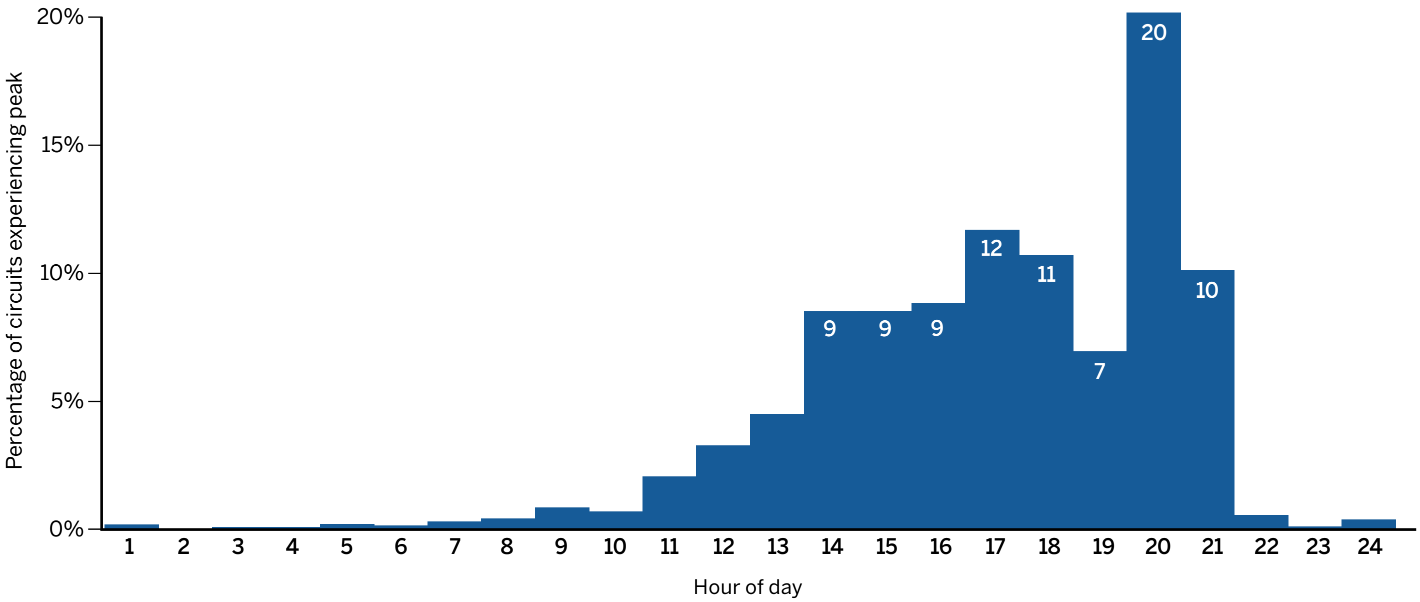
155 California sets electric line extension allowances at expected net distribution revenue divided by a cost of service factor of roughly 16% (California Public Utilities Commission, 2007, pp. 8-9).

156 The company also has the option of applying the 2.75 multiple directly (Public Service Company of Colorado, 2018, Sheet R212).

I/A



Figure 40. San Diego Gas & Electric circuit peaks




Source: Fang, C. (2017, January 20). Direct testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 17-01-020

## 11.3 Distribution Demand Allocators

In any traditional study, a significant portion of distribution plant is classified as demand-related. A newer hourly allocation method may omit this step, assigning distribution costs to all hours when the asset (or a portion of the cost of the asset) is required for service.

For demand-related costs, class NCP is commonly, but often inappropriately, used for allocation. This allocator would be appropriate if each component overwhelmingly served a single class, if the equipment peaks occurred roughly at the time of the class peak, and if the sizing of distribution equipment were due solely to load in a single hour. But to the contrary, most substations and many feeders serve several tariffs, in different classes, and many tariff codes.[157]

### 11.3.1 Primary Distribution Allocators

Customers in a single class, in different areas and served by different substations and feeders, may experience peak loads at different times. Figure 40 shows the hours when each of San Diego Gas & Electric's distribution circuits experienced peak loads (Fang, 2017, p. 21). The peaks are clustered between the early afternoon (on circuits that are mostly commercial) and the early evening (mostly residential), while other circuits experience their peaks at a wide variety of hours.

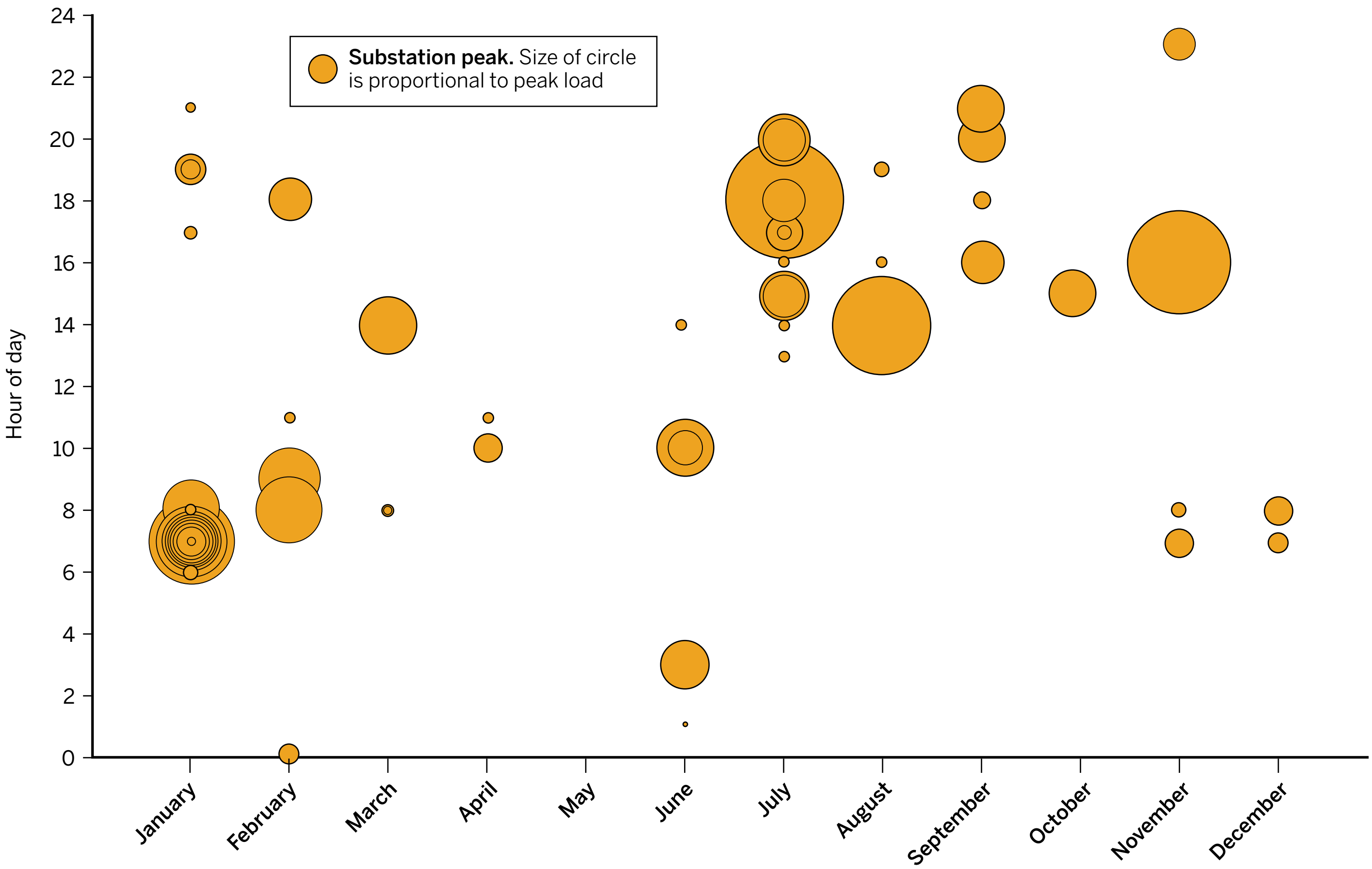
Figure 41 on the next page shows the distribution of substation peaks for Delmarva Power & Light over a period of one year (Delmarva Power & Light, 2016). The area of each bubble is proportional to the peak load on the station. Clearly, no one peak hour (or even a combination of monthly peaks) is representative of the class contribution to substation peaks.

The peaks for substations, lines and other distribution equipment do not necessarily align with the class NCPs. Indeed, even if all the major classes are summer peaking, some of the substations and feeders may be winter peaking, and vice versa. Even within a season, substation and feeder peaks will be distributed to many hours and days.

Although load levels drive distribution costs, the maximum load on each piece of equipment is not the only important load. As explained in Subsection 5.1.3, increased

157 Some utilities design their substations so that each feeder is fed by a single transformer, rather than all the feeders being served by all the transformers at the substation. In those cases, the relevant loads (for timing and class mix) are at the transformer level, rather than the entire substation.

**Figure 41. Month and hour of Delmarva Power & Light substation peaks in 2014**




Source: Delmarva Power & Light. (2016, August 15). Response to the Office of the People's Counsel data request 5-11, Attachment D. Maryland Public Service Commission Case No. 9424

energy use, especially at high-load hours and prior to those hours, can also affect the sizing and service life of transformers and underground lines, which is thus driven by the energy use on the equipment in high-load periods, not just the maximum demand hour. The peak hourly capacity of a line or transformer depends on how hot the equipment is prior to the peak load, which depends in turn on the load factor in the days leading up to the peak and how many high-load hours occur prior to the peak. More frequent events of load approaching the equipment capacity, longer peaks and hotter equipment going into the peak period all contribute to faster insulation deterioration and cumulative line sag, increasing the probability of failure and accelerating aging.

Ideally, the allocators for each distribution plant type should reflect the contribution of each class to the hours when load on the substation, feeder or transformer contributes to the potential for overloads. That allocation could be constructed by assigning costs to hours or by constructing a special demand allocator for each category of distribution equipment. If a detailed allocation is too complex, the allocators for costs should still reflect the underlying reality that distribution costs are driven by load in many hours.

The resulting allocator should reflect the variety of seasons and times at which the load on this type of equipment experiences peaks. In addition, the allocator should reflect the near-peak and prepeak loads that contribute to overheating and aging of equipment. Selecting the important hours for distribution loads and the weight to be given to the prepeak loads may require some judgments. Class NCP allocators do not serve this function.

Rocky Mountain Power allocates primary distribution on monthly coincident distribution peak, weighted by the percentage of substations peaking in each month (Steward, 2014, p. 7). Under this weighting scheme, for example:

- A small substation has as much effect on a month's weighting factor as a large substation. The month with the largest number of large substations seriously overloaded could be the highest-cost month yet may not receive the highest weight since each substation is weighted equally.
- The month's contribution to distribution demand costs is assumed to occur entirely at the hour of the monthly distribution peak, even though most of the substation capacity that peaks in the month may have peaked in a variety of different hours.
- A month would receive a weight of 100% whether each substation's maximum load was only 1 kVA more than its maximum in every other month or four times its maximum in every other month.

This approach could be improved by reflecting the capacity of the substations, the actual timing of the peak hours and the number of near-peak hours of each substation in each month. The hourly loads might be weighted by the square or some other power of load or by using a peak capacity allocation factor for the substation, to reflect the fact that the contribution to line losses and equipment life falls rapidly as load falls below peak.

Many utilities will need to develop additional information on system loads for cost allocation, as well as for planning, operational and rate design purposes. Specifically, utilities should aim to understand when each feeder and substation reaches its maximum loads and the mix of rate classes on each feeder and distribution substation.

In the absence of detailed data on the loads on line transformers, feeders and substations, utilities will be limited to cruder aggregate load data. For primary equipment, the best available proxy may be the class energy usage in the expected high-load period for the equipment, the class contribution to coincident peak or possibly class NCP, but only if that NCP is computed with respect to the peak load of the customers sharing the equipment. Although most substations and feeders serving industrial and commercial customers will also serve some residential customers, and most residential substations and feeders will have some commercial load, some percentage of distribution facilities serve a single class.

The NCP approximation is not a reasonable approximation for finer disaggregation of class loads. For example, there are many residential areas that contain a mix of single-family and multifamily housing and homes with and without electric space heating, electric water heating and solar panels. The primary distribution plant in those areas must be sized for the combined load in coincident peak periods, which may be the late afternoon summer cooling peak, the evening winter heating and lighting peak or some other time — but it will be the same time for all the customers in the area.[158]

Many utilities have multiple tariffs or tariff codes for residential customers (e.g., heating, water heating, all-electric and solar; single-family, multifamily and public housing; low-income and standard), for commercial customers (small, medium and large; primary and secondary voltage; schools, dormitories, churches and other customer types) and for various types of industrial customers, in addition to street lighting and other services. In most cases, those subclasses will be mixed together, resulting in customers with gas and electric space heat, gas and electric water heat, and with and without solar in the same block, along with street lights. The substation and feeder will be sized for the combined load, not for the combined peak load of just the electric heat customers or the combined peak of the customers with solar panels[159] or the street lighting peak.

Unless there is strong geographical differentiation of the subclasses, any NCP allocator should be computed for the

158 Distribution conductors and transformers have greater capacity in winter (when heat is removed quickly) than in summer; even if winter peak loads are higher, the sizing of some facilities may be driven by summer loads.

159 The division of the residential class into subclasses for calculation of the class NCP has been an issue in several recent Texas cases. In Docket No. 43695, at the recommendation of the Office of Public Utility Counsel, the Public Utility Commission of Texas reversed its former method for Southwestern Public Service to use the NCP for a single residential class (instead of separate subclasses for residential customers with and without electric heat), which reduced the costs allocated to residential customers as a whole (Public Utility Commission of Texas, 2015, pp. 12-13 and findings of fact 277A, 277B and 339A). The issue was also raised in dockets 44941 and 46831 involving El Paso Electric Co. El Paso Electric proposed separate NCP allocations for residential customers with and without solar generation, which the Office of Public Utility Counsel and solar generator representatives opposed. Both of these cases were settled and did not create a precedent.

combined load of the customer classes, with the customer class NCP assigned to rate tariffs in proportion to their estimated contribution to the customer class peak.

### 11.3.2 Relationship Between Line Losses and Conductor Capacity

In some situations, conductor size is determined by the economics of line losses rather than by thermal overloads or voltage drop. Even at load levels that do not threaten reliability, larger conductors may cost-effectively reduce line losses, especially in new construction.[160] The incremental cost of larger capacity can be entirely justified by loss reduction (which is mostly an energy-related benefit), with higher load-carrying capability as a free additional benefit.

### 11.3.3 Secondary Distribution Allocators

Each piece of secondary distribution equipment generally serves a smaller number of customers than a single piece of primary distribution equipment. On a radial system, a line transformer may serve a single customer (a large commercial customer or an isolated rural residence) or 100 apartments; a secondary line may serve a few customers or a dozen, depending on the density of load and construction. Older urban neighborhoods often have secondary lines that are connected to several transformers, and some older large cities such as Baltimore have full secondary networks in city centers.[161] In contrast, a primary distribution feeder may serve thousands of customers, and a substation can serve several feeders.

Thus, loads on secondary equipment are less diversified than loads on primary equipment. Hence, cost of service studies frequently allocate secondary equipment on load measures that reflect customer loads diversified for the number of customers on each component. Utilities often use assumed diversity factors to determine the capacity required for secondary lines and transformers, for various numbers of customers. Figure 42 on the next page provides an example of the diversity curve from El Paso Electric Co. (2015, p. 24).

Even identical houses with identical equipment may routinely peak at different times, depending on household composition, work and school schedules and building orientation. The actual peak load for any particular house may occur not at typical peak conditions but because of events not correlated with loads in other houses. For example, one house may experience its maximum load when the family returns from vacation to a hot house in the summer or a very cold one in the winter, even if neither temperatures nor time of day would otherwise be consistent with an annual maximum load. The house next door may experience its maximum load after a water leak or interior painting, when the windows are open and fans, dehumidifiers and the heating or cooling system are all in use.

Accounting for diversity among different types of residential customers, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat, peaking in the winter, and some with fossil fuel heat, peaking in the summer.

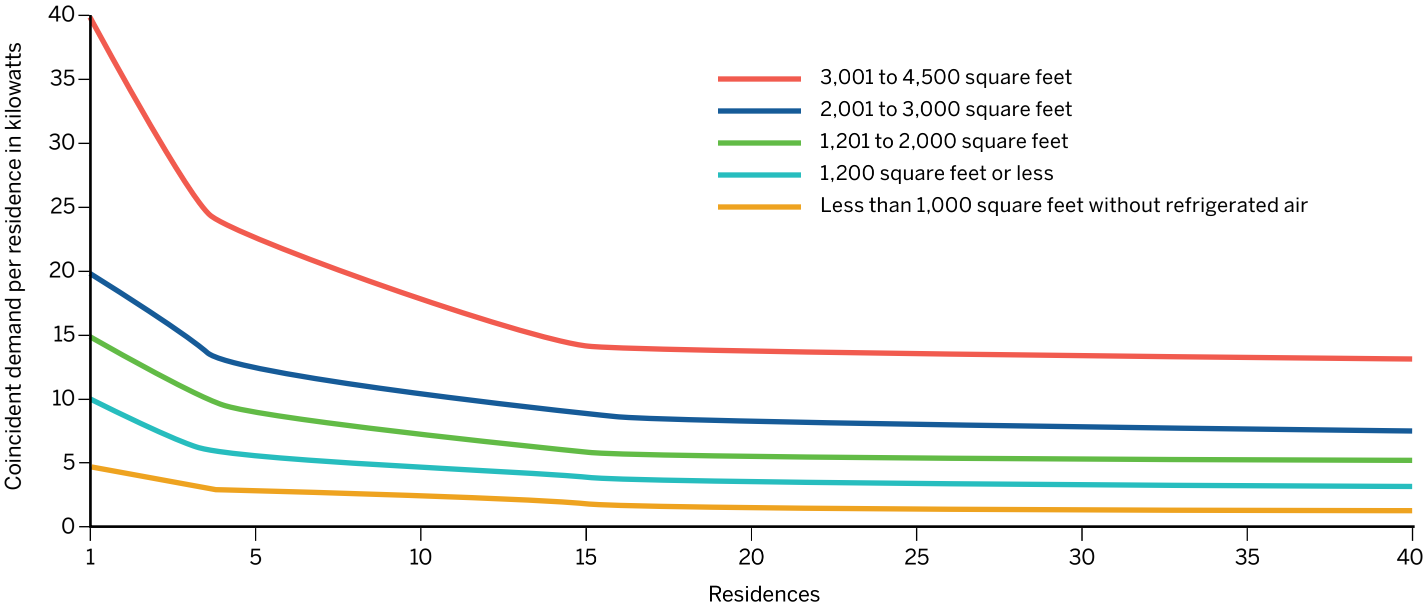
The average transformer serving residential customers may serve a dozen customers, depending on the density of the service territory and the average customer NCP, which for the example in Figure 42 suggests that the customers' average contribution to the transformer peak load would be about 40% of the customers' undiversified load. Thus, the residential allocator for transformer demand would be the class NCP times 40%. Larger commercial customers generally have very little diversity at the transformer level, since each transformer (or bank of transformers) typically serves only one or a few customers.

The same factors (household composition, work and

160 The same is true for increased distribution voltage. Seattle City Light upgraded its residential distribution system from 4 kV to 26 kV in the early 1980s based on analysis done in the Energy 1990 study, prepared in 1976, which focused on avoiding new baseload generation. The line losses justified the expenditure, but the result was also a dramatic increase in distribution system circuit capacity. The Energy 1990 study was discussed in detail in a meeting of the City Council Utilities Committee (Seattle Municipal Archives, 1977).

161 In high-load areas, such as city centers, utilities often operate secondary distribution networks, in which multiple primary feeders serve multiple transformers, which then feed a network of interconnected secondary lines that feed all the customers on the network (See Behnke et al., 2005, p. 11, Figure 8). In secondary networks, the number of transformers and the investment in secondary lines are driven by the aggregate load of the entire network or large parts of the network. The loss of any one feeder and one transformer, or any one run of secondary line, will not disconnect any customer. The existence of the network, the number of transformers and the number and length of primary and secondary lines are entirely load-related. Similar arrangements, called spot networks, are used to serve individual large customers with high reliability requirements. A single spot network customer may thus have multiple transformers, providing redundant capacity.

**Figure 42. Typical utility estimates of diversity in residential loads**




Source: El Paso Electric Co. (2015, October 29). *El Paso Electric Company's Response to Office of Public Utility Counsel's Fifth Request for Information.* Public Utility Commission of Texas Docket No. 44941

school schedules, unit-specific events) apply in multifamily housing as well as in single-family housing. But the effects of orientation are probably even stronger in multifamily housing than in single-family homes. For example, units on the east side of a building are likely to have summer peak loads in the morning, while those on the west side are likely to experience maximum loads in the evening and those on the south in the middle of the day.

Importantly, Figure 42 represents the diversity of similar neighboring single-family houses. Diversity is likely to be still higher for other applications, such as different types and vintages of neighboring homes, or the great variety of customers who may be served from the shared transformers and lines of a secondary network.

Until 2001, the major U.S. electric utilities were required to provide the number and capacity of transformers in service on their FERC Form 1 reports. Assuming an average of one transformer per commercial and industrial customer, these reports typically suggest a ratio ranging from 3 to more than 20 residential customers per transformer, with the lower ratios for the most rural IOUs and the highest for utilities with dense urban service territories and many multifamily consumers.[162] Only about a dozen electric co-ops filed a FERC Form 1 with the transformer data in 2001, and their ratios vary from about 1 transformer per residential customer for a few very rural co-ops to about 8 residential customers per transformer for Chugach Electric, which serves part of Anchorage as well as rural areas.

Utilities can often provide detailed current data from their geographic information systems. Table 30 on the next page shows Puget Sound Energy's summary of the number of transformers serving a single residential customer and the number serving multiple customers (Levin, 2017, pp. 8-9). More than 95% of customers are served by shared transformers, and those transformers serve an average of 5.3 customers. Using the method described in the previous paragraph, an estimated average of 4.9 Puget Sound Energy residential customers would share a transformer, which is close to the actual average of 4.5 customers per transformer shown in Table 30 (Levin, 2017, and additional calculations by the authors).

The customers who have their own transformer may be too far from their neighbors to share a transformer, or local load growth may have required that the utility add a transformer. In many cases, residential customers with

162 Ratios computed using Form 1, p. 429, transformer data (Federal Energy Regulatory Commission, n.d.) and 2001 numbers from utilities' federal Form 861 (U.S. Energy Information Administration, n.d.-a, file 2).

Table 30. Residential shared transformer example

| | With multiple residences per transformer | With single residence per transformer | Total |
|---|---|---|---|
| **Number of transformers** | 197,503 | 47,699 | 245,202 |
| **Number of customers** | 1,054,296 | 47,699 | 1,101,995 |
| **Customers per transformer** | 5.3 | 1 | 4.5 |

Sources: Levin, A. (2017, June 30). Prefiled response testimony on behalf of NW Energy Coalition, Renewable Northwest and Natural Resources Defense Council. Washington Utilities and Transportation Commission Docket No. UE-170033; additional calculations by the authors

individual transformers may need to pay to obtain service that is more expensive than their line extension allowances (see Section 11.2 or Section 15.2).

Small customers will have similar, but lower, diversity on secondary conductors, which generally serve multiple customers but not as many as a transformer. A transformer that serves a dozen customers may serve two of them directly without secondary lines, four customers from one stretch of secondary line and six from another stretch of secondary line running in the opposite direction or across the street.

Where no detailed data are available on the number of customers per transformer in each class, a reasonable approximation might be to allocate transformer demand costs on a simple average of class NCP and customer NCP for residential and small commercial customers and just customer NCP for larger nonresidential customers.

### 11.3.4 Distribution Operations and Maintenance Allocators

Distribution O&M accounts associated with a single type of equipment (FERC accounts 582, 591 and 592 for substations and Account 595 for transformers) should be classified and allocated in the same manner as associated equipment. Other accounts serve both primary and secondary lines and service drops (accounts 583, 584, 593 and 594) or include services to a range of equipment (accounts 580 and 590). These costs normally should be classified and allocated in proportion to the plant in service, for the plant accounts they support, subfunctionalized as appropriate. For example, typical utility tree-trimming activities are almost entirely related to primary overhead lines, with very little cost driven by secondary distribution and no costs for protecting service lines (see, for example, Entergy Corp., n.d.).

### 11.3.5 Multifamily Housing and Distribution Allocation

One common error in distribution cost allocation is treating the residential class as if all customers were in single-family structures, with one service drop per customer and a relatively small number of customers on each transformer.[163] For multifamily customers, one or a few transformers may serve 100 or more customers through a single service line.[164] Treating multifamily customers as if they were single-family customers would overstate their contribution to distribution costs, particularly line transformers and secondary service lines.[165]

This problem can be resolved in either of two ways. The broadest solution is to separate residential customers into two allocation classes: single-family residential and multifamily residential, as we discuss in Section 5.2.[166] Alternatively, the allocation of transformer and service costs to a combined residential class (as well as residential rate design) should take into account the percentage of customers who are in multifamily buildings, and only components that are not shared should be considered customer-related.

163 One large service drop is much less expensive than the multiple drops needed to serve the same number of customers in single-customer buildings. Small commercial customers may also share service drops, although probably to a more limited extent than residential customers.

164 Similarly, if the cost of service study includes any classification of shared distribution plant as customer-related (such as from a minimum system), each multifamily building should be treated as a single location, rather than a large number of dispersed customers. For utilities without remote meter reading, the labor cost for that activity per multifamily customer will be lower than for single-family customers.

165 Allocating transformer costs on demand eliminates the bias for that cost category.

166 If any sort of NCP allocator is used in the cost of service study, the multifamily class load generally should be combined with the load of the type of customers that tend to surround the multifamily buildings in the particular service territory, which may be single-family residential or medium commercial customers.

### 11.3.6 Direct Assignment of Distribution Plant

Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop.

Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.

## 11.4 Allocation Factors for Service Drops

The cost of a service drop clearly varies with a number of factors that vary by class: customer load (which affects the capacity of the service line), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer) and whether customers require three-phase service.

Some utilities, including Baltimore Gas & Electric, attempt to track service line costs by class over time (Chernick, 2010, p. 7). This approach is ideal but complicated. Although assigning the costs of new and replacement service lines just requires careful cost accounting, determining the costs of services that are retired and tracking changes in the class or classes in a building (which may change over time from manufacturing to office space to mixed residential and retail) is much more complex. Other utilities allocate service lines on the sum of customer maximum demands in each class. This has the advantage of reflecting the fact that larger customers require larger (and often longer) service lines, without requiring a detailed analysis of the specific lines in use for each class.

Many utilities have performed bottom-up analyses, selecting a typical customer or an arguably representative sample of customers in each class, pricing out those customers' service lines and extrapolating to the class. Since the costs are estimated in today's dollars, the result of these studies is the ratio of each class's cost of services to the total cost, or a set of weights for service costs per customer. Either approach should reflect the sharing of services in multifamily buildings.

## 11.5 Classification and Allocation for Advanced Metering and Smart Grid Costs

Traditional meters are often discussed as part of the distribution system but are primarily used for billing purposes.[167] These meters typically record energy and, for some classes, customer NCP demand for periodic manual or remote reading and generally are classified as customer-related. Meter costs are then typically allocated on a basis that reflects the higher costs of meters for customers who take power at higher voltage or three phases, for demand-recording meters, for TOU meters and for hourly-recording energy meters. The weights may be developed from the current costs of installing the various types of meters, but as technology changes, those costs may not be representative of the costs of equipment in rates.

In many parts of the country, this traditional metering has been replaced with advanced metering infrastructure. AMI investments were funded in many cases by the American Recovery and Reinvestment Act of 2009, the economic stimulus passed during the Great Recession, but in other cases ratepayers are paying for them in full in the traditional method. In many jurisdictions, AMI has been accompanied by other complementary "smart grid"

167 Some customers who are small or have extremely consistent load patterns are not metered; instead, their bills are estimated based on known load parameters. The largest group of these customers is street lighting customers, but some utilities allow unmetered loads for various small loads that can be easily estimated or nearly flat loads with very high load factors (such as traffic signals). An example of an unmetered customer from the past was a phone booth. Unmetered customers should not be allocated costs of traditional metering and meter reading.

**Table 31. Smart grid cost classification**

| | Legacy approach | | | |
|---|---|---|---|---|
| Smart grid element | Equivalent cost | FERC account | Classification | Smart grid classification |
| **Smart meters** | Meters | 370 | Customer | Demand, energy and customer |
| **Distribution control devices** | Station equipment and devices | 362, 365, 367 | Demand | Demand and energy |
| **Data collection system** | Meter readers | 902 | Customer | Demand, energy and customer |
| **Meter data management system** | Customer accounting and general plant | 903, 905, 391 | Customer and overhead | Demand, energy and customer |

investments. On the whole, these investments include:

- Smart meters, which are usually defined to include the ability to record and remotely report granular load data, measure voltage and power factor, and allow for remote connection and disconnection of the customer.
- Distribution system improvements, such as equipment to remotely monitor power flow on feeders and substations, open and close switches and breakers and otherwise control the distribution system.
- Voltage control equipment on substations to allow modulation of input voltage in response to measured voltage at the end of each feeder.
- Power factor control equipment to respond to signals from the meters.
- Data collection networks for the meters and line monitors.
- Advanced data processing hardware and software to handle the additional flood of data.
- Supporting overhead costs to make the new system work.

The potential benefits of the smart grid, depending on how it is designed and used, include reduced costs for generation, transmission, distribution and customer service, as described in Subsection 7.1.1. A smart meter is much more than a device to measure customer usage to assure an accurate bill — it is the foundation of a system that may provide some or all of the following:

- Benefits at every level of system capacity, by enabling peak load management since the communication system can be used to control compatible end uses, and because customer response to calls for load reduction can be measured and rewarded.
- Distribution line loss savings from improved power factor and phase balancing.
- Reduced energy costs due to load shifting.
- Reliability benefits, saving time and money on service restoration after outages, since the utility can determine which meters do not have power and can determine whether a customer's loss of service is due to a problem inside the premises or on the distribution system.
- Allowing utilities to determine maximum loads on individual transformers.
- Retail service benefits, by reducing meter reading costs compared with manual meter reads and even automated meter reading and by reducing the cost of disconnecting and reconnecting customers.[168]

The installations have also been very expensive, running into the hundreds of millions of dollars for some utilities, and the cost-effectiveness of the AMI projects has been a matter of dispute in many jurisdictions. Since these new systems are much more expensive than the older metering systems and are largely justified by services other than billing, their costs must be allocated over a wider range of activities, either by functionalizing part of the costs to generation, distribution and so on or reflecting those functions in classification or the allocation factor.

Special attention must be given to matching costs and benefits associated with smart grid deployment. The expected benefits spread across the entire spectrum of utility costs, from lower labor costs for meter reading to lower energy

168 The data systems can also be configured to provide systemwide Wi-Fi internet access, although they usually are not. See Burbank Water and Power (n.d.).

Table 32. Summary of distribution allocation approaches

| Element | Method | Comments | Hourly allocation |
|---|---|---|---|
| **Substations** | FUNCTIONALIZATION: Entirely primary<br>CLASSIFICATION: Demand and energy<br>ALLOCATOR: Loads on substations in hours at or near peaks | Reflect effect of energy near peak and preceding peak on sizing and aging | Allocate by substation cost or capacity, then to hours that stress that substation with peak and heating |
| **Poles** | FUNCTIONALIZATION: Entirely primary<br>CLASSIFICATION: Demand and energy*<br>ENERGY ALLOCATOR: Energy or revenue<br>DEMAND ALLOCATOR: Loads in hours at or near peaks | Pole costs driven by revenue expectation | As primary lines |
| **Primary conductors** | FUNCTIONALIZATION: Entirely primary<br>CLASSIFICATION: Demand and energy*<br>ENERGY ALLOCATOR: Energy or revenue<br>DEMAND ALLOCATOR: Loads in hours at or near peaks | • Distribution network is installed due to revenue potential<br>• Sizing determined by loads in and near peak hours | • Cost associated with revenue-driven line extension to all hours<br>• Cost associated with peak loads and overloads on distribution of line peaks and high-load hours |
| **Line transformers** | FUNCTIONALIZATION: Entirely secondary<br>CLASSIFICATION: Demand and energy*<br>ENERGY ALLOCATOR: Secondary energy<br>DEMAND ALLOCATOR: Diversified secondary loads in peak and near-peak hours | Reflect diversity | Distribution of transformer peaks and high-load hours |
| **Secondary conductors** | FUNCTIONALIZATION: Entirely secondary<br>CLASSIFICATION: Demand and energy*<br>ENERGY ALLOCATOR: Energy or revenue<br>DEMAND ALLOCATOR: Loads in hours at or near peaks | Energy is more important for underground than overhead | Distribution of line peaks and high-load hours |
| **Meters** | FUNCTIONALIZATION: Advanced metering infrastructure to generation, transmission and distribution, as well as metering<br>ALLOCATOR FOR CUSTOMER-RELATED COSTS: Weighted customer | Allocation of generation, transmission and distribution components depends on use of advanced metering infrastructure | N/A |

* Except some to customer, where a significant portion of plant serves only one customer

costs due to load shifting and line loss reduction. Legacy methods for allocating metering costs as primarily customer-related would place the vast majority of these costs onto the residential rate class, but many of the benefits are typically shared across all rate classes. In other words, the legacy method would give commercial and industrial rate classes substantial benefits but none of the costs.

Table 31 identifies some of the key elements of smart grid cost and how these would be appropriately treated in an embedded cost of service study. These approaches match smart grid cost savings to the enabling expenditures.

## 11.6 Summary of Distribution Classification and Allocation Methods and Illustrative Examples

The preceding discussion identifies a variety of methods used to functionalize, classify and allocate distribution plant. Table 32 summarizes the application of some of those methods, including the hourly allocations that may be applicable for modern distribution systems with:

- A mix of centralized and distributed resources, conventional and renewable, as well as storage.
- The ability to measure hourly usage on the substations and feeders.
- The ability to estimate hourly load patterns on transformers and secondary lines.

**Table 33. Illustrative allocation of distribution substation costs by different methods**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **Class NCP: substation (legacy)** | $9,730,000 | $9,730,000 | $7,297,000 | $3,243,000 | $30,000,000 |
| **Average and peak** | $10,056,000 | $10,056,000 | $8,100,000 | $1,788,000 | $30,000,000 |
| **Hourly** | $9,939,000 | $10,533,000 | $9,009,000 | $519,000 | $30,000,000 |

Note: Numbers may not add up to total because of rounding.

Where the available data or analytical resources will not support more sophisticated analyses of distribution cost causation, the following simple rules of thumb may be helpful.

- The only costs that should be classified as customer-related are those specific to individual customers:
  - Basic metering costs, not including the additional costs of advanced meters incurred for system benefits.
  - Service lines, adjusting for shared services in buildings with multiple tenants.
  - For very rural systems, where most transformers and large stretches of primary line serve only a single customer (and those costs are not recovered from contributions in aid of construction), a portion of transformer and primary costs.
- Other costs should be classified as a mix of energy and demand, such as using the average-and-peak allocator.
- The peak demand allocation factor should reflect the distribution of hours in which various portions of distribution system equipment experience peak or heavy loads. If the utility has data only on the time of substation peaks, the load-weighted peaks can be used to distribute the demand-related distribution costs to hours and hence to classes.

## 11.6.1 Illustrative Methods and Results

The following discussion and tables show illustrative methods and results for several of the key distribution accounts, focused only on the capital costs. The same principles should be applied to O&M costs and depreciation expense. These examples use inputs from tables 5, 6, 7 and 27.

### Substations

Table 33 shows three methods for allocating costs of distribution substations. The first of these is a legacy method, relying solely on the class NCP at the substation level.[169] The second is an average-and-peak method, a weighted average between class NCP and energy usage. The third uses the hourly composite allocator, which includes higher costs for hours in which substations are highly loaded.

### Primary Circuits

Distribution circuits are built where there is an expectation of significant electricity usage and must be sized to meet peak demands, including the peak hour and other high-load hours that contribute to heating of the relevant elements of the system. Table 34 on the next page illustrates the effect of four alternative methods. The first, based on the class NCP at the circuit level, again produces unreasonable results for the street lighting class. The second, the legacy minimum system method, is not recommended, as discussed above. The third and fourth use a simple (average-and-peak) and more sophisticated (hourly) approach to assigning costs based on how much each class uses the lines and how that usage correlates with high-load hours.

### Transformers

Line transformers are needed to serve all secondary voltage customers, typically all residential, small general

169 The street lighting class NCP occurs in the night, and street lighting is a small portion of load on any substation, so the street lighting class NCP load rarely contributes to the sizing of summer-peaking substations. The NCP method treats off-peak class loads as being as important as those that are on-peak. This is particularly inequitable for street lighting, which is nearly always a load caused by the presence of other customers who collectively justify the construction of a circuit.

**Table 34. Illustrative allocation of primary distribution circuit costs by different methods**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **Class NCP: circuit (legacy)** | $69,565,000 | $69,565,000 | $43,478,000 | $17,391,000 | $200,000,000 |
| **Minimum system (legacy)** | $113,783,000 | $51,783,000 | $24,739,000 | $9,696,000 | $200,000,000 |
| **Average and peak** | $67,041,000 | $67,041,000 | $53,997,000 | $11,921,000 | $200,000,000 |
| **Hourly** | $66,258,000 | $70,221,000 | $60,059,000 | $3,462,000 | $200,000,000 |

Note: Numbers may not add up to total because of rounding.

service and street lighting customers and often other customer classes as well. We present four methods in Table 35: two archaic and two more reflective of dynamic systems and more granular data. All of these apportion no cost to the primary voltage class, which does not use distribution transformers supplied by the utility.

The first method is to apportion transformers in proportion to the class sum of customer noncoincident peaks. This method is not recommended because it fails to recognize that there is great diversity between customers at the transformer level; as noted in Subsection 11.3.3, each transformer in an urban or suburban system may serve anywhere from five to more than 50 customers. The second is the minimum system method, also not recommended because it fails to recognize the drivers of circuit construction, as discussed in Section 11.2. The third is the weighted transformers allocation factor we derive in Section 5.3 (Table 7), weighting the number of transformers by class at 20% and the class sum of customer NCP (recognizing that the diversity is not perfect) at 80%. The last is an hourly energy method but excluding the primary voltage class of customers.

### Customer-Related Costs

The final illustration shows two techniques for the apportionment of customer-related costs, based on a traditional customer count and a weighted customer count. Even for simple meters used solely for billing purposes, larger customers require different and more expensive meters. There are fewer of them per customer class, but the billing system programming costs do not vary by number of customers. In addition, a weighted customer account is also relevant to customer service, discussed in the next chapter, because the larger use customers typically have access to superior customer service through "key accounts" specialists who are trained for their needs.

**Table 35. Illustrative allocation of distribution line transformer costs by different methods**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **Customer NCP (legacy)** | $32,258,000 | $16,129,000 | $0 | $1,613,000 | $50,000,000 |
| **Minimum system (legacy)** | $32,461,000 | $14,773,000 | $0 | $2,766,000 | $50,000,000 |
| **Weighted transformers factor** | $29,806,000 | $14,903,000 | $0 | $5,290,000 | $50,000,000 |
| **Hourly** | $23,810,000 | $23,810,000 | $0 | $2,381,000 | $50,000,000 |

Note: Numbers may not add up to total because of rounding.

**Table 36. Illustrative allocation of customer-related costs by different methods**

| | Residential | Secondary commercial | Primary industrial | Street lighting | Total |
|---|---|---|---|---|---|
| **Unweighted** | | | | | |
| **Customer count** | 100,000 | 20,000 | 2,000 | 50,000 | 172,000 |
| **Customer factor** | 58% | 12% | 1% | 29% | 100% |
| **Customer costs** | $58,140,000 | $11,628,000 | $1,163,000 | $29,070,000 | $100,000,000 |
| **Weighted** | | | | | |
| **Weighting factor** | 1 | 3 | 20 | 0.05 | |
| **Customer count** | 100,000 | 60,000 | 40,000 | 2,500 | 202,500 |
| **Customer factor** | 49% | 30% | 20% | 1% | 100% |
| **Customer costs** | $49,383,000 | $29,630,000 | $19,753,000 | $1,235,000 | $100,000,000 |

Note: Numbers may not add up to total because of rounding.

Table 36 first shows a traditional calculation based on the actual number of customers. Then it shows an illustrative customer weighting and a simple allocation of customer-related costs based on that weighting. Each street light is treated as a tiny fraction of one customer; although there are tens of thousands of individual lights, the bills typically include hundreds or thousands of individual lights, billed to a city, homeowners association or other responsible party.[170]

170 In some locales, street lighting is treated as a franchise obligation of the utility and is not billed. In this situation, there are no customer service or billing and collection expenses.

# 12. Billing and Customer Service in Embedded Cost of Service Studies

Many utilities classify billing and customer service costs, often termed retail service costs, as almost entirely customer-related and allocate these costs across classes based on the number of customers. This chapter describes how these costs can be allocated in a more granular and detailed way.

## 12.1 Billing and Meter Reading

Most utilities bill customers either monthly or bimonthly. The reason for this is relatively simple: If billed less frequently, the bills would be very large and unmanageable for some consumers; if billed more frequently, the billing costs would be an unacceptable part of the total cost. As noted in Subsection 3.1.5, billing closer to the time of consumption provides customers with a better understanding of their usage patterns from month to month, which may assist them in increasing efficiency. There are exceptions: Many water, sewer and even electric utilities serving seasonal properties may render bills only once or twice a year.[171]

It is important to recognize these cost drivers in the classification of billing costs. From a cost causation perspective, the reason for frequent billing is that usage drives the size of the bill. We receive annual bills for magazine subscriptions because the quantity we will use (one per week or month) is very small and predictable. In some states, rules of the regulatory commission require billing on a specified interval. For example, in Washington state, the rules require billing not less than bimonthly (Washington Administrative Code Title 480, Chapter 100, § 178[1][a]). In this situation, billing frequency in excess of that required by law or regulation is driven by consumption. The portion of the costs of reading meters and billing more frequently should be classified and allocated according to appropriate measures of usage, rather than customer count.

Manual reading of the meters of large customers typically takes longer than for small customers, both because of travel distance among larger customers and the complexity of metering typical of large customers (TOU or demand-metered). In some cases, small customer meters are read manually but large customers are remotely metered; the additional costs of the equipment for that remote metering should be assigned to the classes that use remote metering. As noted in Section 11.5, unmetered customers such as streetlights should not be allocated meter reading costs.

For utilities with AMI, any meter reading costs arising from customers opting out of AMI should be recovered either from the opt-out customers or functionalized, classified and allocated in proportion to the AMI costs, because opt-outs are part of the cost of obtaining the benefits of AMI.

The costs of billing, payment processing and collections for special services (e.g., line extensions and relocations) can end up in Account 903 for some utilities. These are overhead costs, not customer costs, and should be either classified or allocated as an overhead expense.[172]

Some utilities provide on-bill financing for energy efficiency, renewable energy or demand response investments that the utility (or a third party) makes at the customer premises. Where this occurs, a portion of the billing cost should be assigned to the nonservice cost element.

## 12.2 Uncollectible Accounts Expenses

Uncollectible accounts expenses are the expenses from customers who have not paid their bills, due to financial

171 This is also the case for California customers who opt out of AMI (California Public Utilities Commission, 2014).

172 The same is true for any uncollectible charges for special services. If there is direct assignment of uncollectibles, charges related to non-energy billings or claims should be segregated from the remainder of Account 904 and directly assigned as overhead expenses.

distress, bankruptcy or departure from the service territory.[173] Some analyses erroneously allocate the costs of former customers to the classes of current customers on a per-customer basis or by direct assignment. However, these costs are not caused by any current customer in any particular class.[174] Although certain accounts have unpaid electric bills, those accounts are former customers who are no longer members of any class.

Uncollectible accounts are related to class revenue in two ways. First, the higher the bills of a particular class, the more revenue is at risk of becoming uncollectible. Second, if the customer had shut down or left before rates were set, most of the costs reflected in the uncollectible bills would have been allocated to the remaining customers, in all classes. Hence, uncollectible revenues should be classified as revenue-related and allocated in proportion to revenues, not customer number.[175]

The treatment of four elements should be coordinated in the cost of service study:

- Uncollectible accounts expenses.
- Late payment revenues if charged to all classes (sometimes called forfeited discounts, often recorded in FERC Account 450 in the Uniform System of Accounts).
- Customer deposits, which protect utilities against uncollectibles and which offset rate base for most utilities in North America.
- Interest paid to customers on customer deposits.

If uncollectible accounts expenses are assigned as an overhead expense based on revenue, then all of these four items should be allocated based on revenue.

On the other hand, if uncollectible accounts expenses are directly assigned to the originating class or using a customer allocator, then late payment revenues and customer deposits should be assigned in the same manner.

Although an allocation based on revenue is more appropriate, the consistent allocation of these four items by either revenue or direct assignment may not have a large effect on the cost of service study, because direct-assigned late payment revenues and deposits partly offset direct-assigned uncollectible accounts expenses.

The worst cost allocation outcome is inconsistency: assigning uncollectible accounts expenses largely to residential customers using direct assignment or a per-customer allocation while using a broad allocation method for late payment charges and customer deposits, even though both of these items are also largely paid by residential customers.

## 12.3 Customer Service and Assistance

Utilities frequently classify customer service and information expenses as customer-related and allocate them in proportion to customer number. This approach is not reasonable, because these expenses are more likely to vary with class energy consumption and revenues.

In general, larger customers have more complicated installations, metering and billing and warrant more time and attention from a utility. A utility customer service staff does not spend as much time and attention on each residential customer as on each large commercial or industrial customer, considering the fact that the larger customers may have bills 100 or 1,000 times that of the average residential customer. Indeed, most utilities have key accounts specialists — highly trained customer service personnel who concentrate on the needs of the largest customers. Large customers may also have more complex billing arrangements, multiple delivery points, demand charges, campus billing, interruptible rates and credits, transformer ownership credits and additional complications that require more time from engineering, legal and rate staff, supervisors and higher management, so the billing costs should be weighted proportionately to the customer classes with complex arrangements.

The alternative to a simple customer allocator for customer service costs may be to use a weighted customer

173 For most utilities, the residential class produces most of the uncollectible accounts expenses, in part because large customers are more often required to post deposits or demonstrate good financial standing. However, when large customers' bills are uncollectible, often due to bankruptcy, the amounts can be very large.

174 Texas has one of the strongest precedents on this issue for utilities not in ERCOT and therefore not subject to competition. See Public Utility Commission of Texas (2018, p. 47, findings of fact 303-305).

175 Texas and California have treated these costs as overhead costs, allocated by revenue to all customer classes.

allocator — in which larger customers are assigned a multiple of the costs assigned to smaller customers — or a combination of customer number and class revenue. The retail allocators should be derived from the relative cost or effort required per customer for each class.

Most utilities can segregate costs for key accounts and identify the customer classes for which these services are provided. Although these costs should be recorded in customer service costs (accounts 907 to 910), they can appear in other accounts. Wherever they appear, they should be assigned to the classes that use them. The costs should be assigned mostly to the largest commercial and industrial customers who receive the services, perhaps with a small amount allocated to classes with smaller nonresidential customers.[176]

Account 908, which FERC identifies as customer assistance expenses, contains general advice and education on electrical safety and energy conservation. Account 909 involves informational advertising. Those activities are generally not extensive (or expensive), and allocation is not usually controversial. But many utilities also book to this account energy efficiency expenditures, which can represent a few percent of consumer bills. If there are significant costs in this account, they are likely to be dominated by energy efficiency programs, which should be allocated as described in Section 14.1.

## 12.4 Sales and Marketing

Sales and marketing costs are often erroneously allocated by the number of customers rather than the purpose of sales and marketing expenses: to increase electric loads (e.g., by economic development or load retention). Since the purpose of these costs is to increase contributions to margin from new or existing customers, thereby reducing the need for future rate increases, the costs should be allocated by base rate revenue or another broad allocation factor such as rate base.

Some sales and marketing funds are used to promote important public policy programs (such as energy efficiency or electric vehicles, discussed further in sections 14.1 and 7.1.3, respectively). Other sales and marketing efforts, however, may promote programs that ratepayers arguably should not fund at all (e.g., promotion of inefficient electric resistance heating by a utility that is almost entirely fossil fuel-based, through sponsorships and advertising) and should be examined closely in revenue requirements cases.

176 A few large customers billed on multiple small or medium commercial tariffs may receive key-customer services, such as franchisees, government agencies and small accounts attached to large ones.

# 13. Administrative and General Costs in Embedded Cost of Service Studies

Utilities have very significant administrative overhead costs, including general plant (office buildings, vehicles, computer systems), labor costs (executive compensation, employee benefits) and the cost of outside services. Some cost of service studies functionalize a portion of each category of general plant and overhead costs to each of the first four functions. Other cost of service studies treat overhead as a function and allocate those costs to classes in proportion to the costs allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions.[177] In this regard, the structure of the cost of service does not constrain or distort the allocation of overhead costs.

Overheads are costs that cannot be directly assigned to particular functions. The overhead category includes the capital costs and depreciation expenses recorded as general plant in accounts 389 to 399 (which includes office buildings and warehouses), property taxes in Account 408, employment taxes in Account 408.2 and the O&M expenses recorded as administrative and general in accounts 920 to 935.

## 13.1 Operations and Maintenance Costs in Overhead Accounts

Some costs included as A&G expenses may be more accurately treated as O&M for specific functions. Utilities do not all interpret the FERC Uniform System of Accounts in the same way. For example, a utility may include some or all of its expenses for procuring electricity and fuel in Account 920 (administrative salaries) and Account 921 (office expenses). These costs should be treated as energy-related, either by being refunctionalized to fuel costs and Account 557 (other power supply expenses) or allocated in proportion to those costs or on energy. Similarly, some utilities include all or a portion of the major accounts expenses (discussed in Section 12.3) in accounts 920 and 921. These should be reclassified to customer service and assigned to the classes with the large customers who receive these services.

## 13.2 Labor-Related Overhead Costs

Some of the A&G accounts in the standard utility accounting systems serve a single function and are driven by a single factor. For example, employment taxes, pension expenses and other employee benefits vary with the number of employees and salaries and are generally functionalized in proportion to the labor in each function or are allocated using the special labor allocation factor calculated earlier in the process, based on how the labor costs in each function were previously allocated among the classes. If a labor allocator is not available, nonfuel O&M is often used as a reasonable proxy for labor.[178]

If the administrative overheads are available disaggregated by department or function, the human resources or personnel office should also be functionalized or allocated in proportion to labor. For administrative labor and other costs that cannot be directly functionalized, see Section 13.5.

## 13.3 Plant-Related Overhead

Accounts 924 (property insurance) and 925 (injuries and damages) are clearly plant-related and are generally functionalized or allocated in proportion to plant, with the exception of workers' compensation expenses in Account 925,

177 In setting wholesale transmission rates, FERC allocates A&G and general plant costs among jurisdictions by labor, with the exception of property insurance Account 924 (by plant) and regulatory commission expenses (directly assigned). As described in sections 5.2 and 5.3, this treatment is overgeneralized.

178 If nonfuel O&M is used instead of labor, transmission wheeling expenses, uncollectible accounts expenses and regulatory amortizations to operation and maintenance accounts should also be excluded, since these costs do not require supervision and administrative cost.

which are labor-related.[179] The same is true for property taxes that are based on the assessed value of each utility facility.[180] Typically, an allocator based on net plant (or net plant less deferred taxes) is used, but the allocation should reflect the method by which taxes are assessed in each state.

## 13.4 Regulatory Commission Expenses

The benefits to customers of the regulatory oversight funded through FERC Account 928 will normally be distributed more in proportion to the classes' total bills, including both investment-related costs and operating expenses, rather than to the number of customers in the classes. In terms of cost causation, the regulatory assessment covers expenditures on many types of proceedings, including (depending on the jurisdiction) rate cases, resource planning, project certification, review of investments, power purchase contracts and fuel expenses. Demand and energy use are the major contributors to the size of the assessment and the cost of its regulatory efforts. Depending on the jurisdiction and the distribution of the regulator's efforts, the most equitable allocator may be class revenues or energy consumption.[181]

## 13.5 Administrative and Executive Overhead

Many of the standard A&G accounts serve multiple functions. Administrative salaries pay employees in human resources, financing, public relations, regulatory affairs, the legal department, purchasing and senior management. Some of their work is driven by employee numbers (e.g., human resources), others by capital investment (finance) and most by a mix of labor, fuel procurement, nonfuel expenses and capital investments, including dealing with disputes with suppliers, customers, regulators and other parties. Outside purchased services may include consultants on new power plants, fuel and equipment procurement, power transactions, environmental compliance, worker safety and many other activities.

These costs are driven by the utility's entire operation, including labor, other O&M and plant investment. If these corporate overheads can be differentiated in sufficient detail (sections 13.1, 13.2 and 13.3), they can be functionalized or allocated to specific cost categories. Otherwise, these costs can be allocated in proportion to class revenue (or the total of other cost allocations).

Utilities agree to franchise payments (in Account 927) to gain access to customers and the associated revenues; thus franchise payments should be allocated in proportion to total revenues or other allocated costs.

## 13.6 Advertising and Donations

Some utilities assign Account 930.1 (general advertising) or certain donations as customer-related. This treatment is erroneous. General advertising is not trying to inform customers of anything they need to know about their regulated utility service (the purpose of Account 909) or sell them anything (Account 913). Rather Account 930.1 includes "cost of advertising activities on a local or national basis of a good will or institutional nature, which is primarily designed to improve the image of the utility or the industry" (18 C.F.R. § 367.901[d]). If allowed in rates at all, these costs are clearly overheads, even if the expenditures are largely intended to affect the opinions of residential customers (or voters). To the extent that some donations are allowed in rates (as in Texas), they also are image-building and charitable overhead and, as such, should not be assigned by the number of customers.

179 As a refinement, a study could be done to determine workers' compensation costs by functions. Customer service representatives (largely customer-related in Account 903) are likely to have lower workers' compensation costs than power plant operators or power line workers.

180 For publicly owned utilities, the equivalent may be payments in lieu of taxes.

181 Many utilities allocate these costs by base rate revenues; a more appropriate allocator would be total revenues given that fuel and other costs collected in riders are also regulated and planning and certification activities related to the rider costs constitute a significant portion of the burden on regulators.

# 14. Other Resources and Public Policy Programs in Embedded Cost of Service Studies

## 14.1 Energy Efficiency Programs

Energy efficiency costs have three effects on the revenue requirement that will be recovered through rates. First, energy efficiency shrinks the size of the pie of non-energy efficiency costs that have to be split up, because the utility will need less generation, transmission and distribution in the long run, and utilities that own generation may be able to earn some export revenues to offset other costs. Since utilities generally undertake energy efficiency only if it is less expensive than the avoided costs (sometimes measured as short run, sometimes as long run, and including or excluding environmental costs), energy efficiency tends to reduce total costs, at least in the long term.

Energy efficiency programs typically reduce generation, transmission and distribution costs, and hence also some of the associated overheads, but not most retail service costs, such as metering and billing.[182] In restructured utilities, energy efficiency load reductions tend to reduce the prices that all customers pay for generation services, as well as avoiding transmission and distribution investments. These benefits typically are dominated by energy savings, with a portion being demand-related. Some utilities collect energy efficiency costs from all customers, on an equal cents-per-kWh basis or using an energy/demand allocator. Where this is done, the allocation of program costs should generally follow the framework for revenue collection.

Second, a program that reduces the loads of one class shrinks its share of the cost pie, increasing other classes' shares of the pie. For the participating class, the reduction in both the size of the pie and the class's share of the pie reduces customers' cost allocation. For each class participating in each program, the program reduces the bills of participants and the costs allocated to the class. Thus, some utilities have assigned the costs of each energy efficiency program to the participating classes. But for some other class, the increase in its share of the costs may be either larger or smaller than the effect on the size of the total pie, so its cost allocation may either rise or fall due to the energy efficiency.

Thus, cost-effective energy efficiency, with the costs allocated to classes based on the class share of the system benefits, can result in nonparticipating classes paying more than they would without energy efficiency. Conversely, assigning the costs directly to the participating class or classes can result in the participants paying more for energy efficiency programs than they benefit from the shrinking of the revenue requirements and of their share, leaving them worse off. These are extreme situations. With highly cost-effective programs and broad participation, all classes are very likely to benefit from energy efficiency, no matter how the costs are allocated. But the net benefits can be inequitably allocated.

The cost effects of energy efficiency differ between the short term and the long term. The costs of energy efficiency investment are often incurred in the year of program implementation, while the benefits stretch on for many years. In 2018, the customers will be paying roughly the costs of the 2018 program, while nonparticipating customers in 2018 are primarily receiving the benefits of energy efficiency investment that occurred in the past. This could be another source of misalignment between cost recovery and benefits, particularly if there are changes over time in the cost recovery method or the relative benefits to each customer class.

Energy efficiency costs are typically caused by the opportunity to reduce total costs to consumers. For most costs, revenue requirements would be lower if customers did less to require the utility to incur those costs. Customers

182 Energy efficiency programs targeted to low-income customers can reduce collection costs, uncollectibles and other burdens on the utility and other customers.

whose load growth requires upgrades to their service drops and transformers, extension of three-phase primary distribution and retention of more hydro energy that could have been exported would increase costs to the system. The same is true for customers who want their service drops underground for aesthetic reasons. Other customers should not bear those costs, so the costs are assigned or allocated to the participating class and billed (more or less) to the customer demanding the service. If customers do not want to pay the costs, they should not increase their load or request more expensive services.

The allocation of energy efficiency costs should reflect both the system benefits and the benefits to the participating classes, while avoiding making any class worse off.

Unlike other costs, energy efficiency costs produce benefits for the participating class and entire system. Utilities do not want to discourage participation in energy efficiency efforts, and they recognize there are benefits beyond the participant. In principle, the cost of service study might allocate all energy efficiency costs to the participating rate classes, offset by all the system benefits of energy efficiency. In practice, it would be difficult. The cost savings in 2020, for example, will result from expenditures made in earlier energy efficiency programs, and relatively little savings will be realized for nonparticipants in 2020 from the activities underway in that year. Determining the load reductions in 2020 from those prior years' programs, the cost savings from the load reductions and the class responsibility for those savings would be quite complex.

The allocation of energy efficiency costs should reflect both the system benefits from energy efficiency and the benefits to the participating classes, while avoiding making any class worse off. If a utility has high avoided costs and low embedded costs, the first solution may result in a class being charged for all the costs of the energy efficiency it undertakes, even though most of the benefit flows to other classes, leaving the participant class worse off than if it had not participated. That outcome would not be equitable and would not encourage the class to engage in further efficiency. If a utility has relatively low avoided costs and high embedded costs, the second option may result in the participating class's revenue requirements falling by more than the total net benefit of the energy efficiency program, leaving other classes with higher bills. That outcome would also be inequitable and may inspire each class to oppose energy efficiency proposals for the other classes.

The allocation of energy efficiency program costs should avoid both of these extremes, which may lead to the use of a split between energy-related and demand-related, direct assignment to participating classes or a combination of the two approaches (such as 50% of the costs being directly assigned and the rest allocated based on energy usage).

To avoid these problems, the utility could estimate the effects of recent or planned energy efficiency on revenue requirements for each class, for alternative allocations. This analysis would include the long-term annual revenue requirements for three cases:

1. Actual or planned energy efficiency spending and load reductions, with energy efficiency costs assigned to the participating classes and system revenue requirements allocated roughly as they would flow through the cost of service study.
2. Actual or planned energy efficiency spending and load reductions, with energy efficiency costs allocated in proportion to avoided costs (using weighted energy or other allocators reflecting the composition of avoided costs) or total revenues, and system revenue requirements allocated roughly as they would flow through the cost of service study.
3. No energy efficiency, resulting in higher loads, higher energy costs, lower export revenues and higher T&D costs.

The difference between case 1 and case 3 would show the effect on rate classes of assigning energy efficiency costs by class, and the difference between case 2 and case 3 would show the effect on rate classes of allocating energy efficiency costs in proportion to the system benefits. Based on that analysis, the cost of service study should use an allocation approach that is fair to all classes, avoiding a situation in which one class is paying for its own energy efficiency efforts that are disproportionately benefiting other classes or, conversely, paying for energy efficiency for other classes and receiving little of the benefit.

## 14.2 Demand Response Program and Equipment Costs

Demand response programs may avoid generation, transmission and distribution investments depending on the specifics of the program and may avoid high purchased power and transmission costs incurred for peak periods or contingencies. The costs of marketing the programs, and even payments to participants, may appear in a customer service account, such as Account 908. Despite their location in this account, the costs are not customer-related. They are resource costs that benefit all customers.

Utility demand response programs are designed to avoid capacity and energy costs and line losses for short-duration loads during times of system stress. The program costs may include investments and expenses at utility offices (computers, software and labor), installations on the distribution system (sensors and communication equipment) and installations on customer premises (controls). These costs are incurred to avoid peak capacity (and sometimes associated energy) costs on the generation system and sometimes on the transmission and distribution systems as well.

The demand response costs should be functionalized across all affected functions and allocated based on metrics of peak usage that relate to the period for which they are incurred — the hours contributing to highest stress. Where demand response provides benefits outside the highest-stress hours, such as by providing operating reserves (which reduce the need to run uneconomic fossil-fueled generation), a portion of the demand response costs should be allocated to the hours when demand response provides those benefits.

Some investments provide not only demand response but also load shifting or energy efficiency. Examples include controls for water heaters, space cooling and space heating and swimming pool pumps. These programs can reduce energy costs, including increasing load in periods with excess renewables that would otherwise be curtailed. Allocation of these costs should reflect the mix of benefits, including peak reductions, reduced reserve costs and reduced energy costs.

For programs that are operated only infrequently under conditions of bulk generation shortage (e.g., industrial interruptible load), the loads that were curtailed should be added back to the relevant class loads, and the costs of the programs — both outreach and incentive payments — should be treated as purchased power and allocated either to generation demand or to the specific hours when the program could be called.[183] Some utilities remove interruptible demand from the associated class load before allocating costs and allocate the costs of the program back to the participating class; that approach can be reasonable, as long as the interruptibility provides benefits equivalent to the utility functions for which the class allocation is reduced.[184] In no case should a cost of service study both reduce the participant class loads for demand response and allocate the costs to all classes; that would double count the benefit to the participating class.

Other programs with more frequent operations or wider benefits than emergency bulk generation should be assigned more broadly to generation, transmission and distribution based on program design. For example, if a demand response or storage program is developed simultaneously to improve the reliability and efficiency of the distribution system (i.e., a targeted nonwires alternative investment program) and to provide bulk power benefits, the costs could be assigned partly to each function as discussed above.[185]

In certain cases, utilities may directly own demand

183 It is generally inappropriate to pay customers to participate in a demand response program, subtract demand response capacity from the loads used for deriving allocation factors and also allocate the costs of the program to nonparticipating classes. Paying the participants and reducing their class loads pays twice for the same resource. The participants should be paid, of course, but all load should pay for the service that the program provides.

184 Many legacy interruptible rates require long lead times, allow only a limited number of annual interruptions, limit the length of each interruption and allow customers to ride through an interruption for a modest penalty. These rates may reduce the cost of serving the interruptible customers but do not fully replace equivalent amounts of generation and transmission.

185 Although a program theoretically could be designed only to have targeted distribution benefits without bulk power benefits, that may not be the most cost-effective program design.

response or load management equipment at customer premises to enable utility or consumer control of space conditioning, water heating, irrigation pumping and other loads. This type of investment's primary purpose is to enable peak load management, but it may also provide ancillary services and shifting of energy between periods. Although located within the distribution system, it is functionally different from most other distribution system plant in that it directly offsets the need for generation and transmission expenditures. For this reason, these costs should be classified and allocated differently from other distribution plant.

## 14.3 Treatment of Discounts and Subsidies

The decision to reduce the revenue responsibility of some customers increases the revenue responsibility of other customers. There are a variety of reasons for legislatures and regulators to provide discounts. Some are cost-based (such as for off-peak or interruptible service), in which case other customers are not truly providing a subsidy. Other discounts are truly subsidies, most commonly for low-income residential customers (unless justified by a substantially different load profile) and for financially distressed businesses — especially agricultural irrigation[186] and businesses that are major employers.

A common example is the difference between the revenues that low-income consumers would have paid under the standard residential tariff (or a tariff designed to recover the costs appropriately allocated to a low-income class) and what they actually pay under discounted low-income tariffs.[187] Where those subsidies exist, the cost of service study must address how to recover the subsidies through adding to the revenue responsibility of other customers. The decision as to whether the subsidy should be recovered from the class whose members receive the discount or from all customers is a matter of public policy, which is sometimes settled by the legislature[188] and other times left to the regulator's judgment. If the subsidy is recovered within the discounted class, the discount does not affect cost allocation to the class because the costs remain within the class and the subsidy shows up in the form of reduced revenues (and may thus result in higher rates for the remainder of the residential class). But if the subsidy is to be redistributed to other classes, it is appropriate for inclusion in the cost of service study as a cost or revenue adjustment to be apportioned across classes.[189]

As a practical matter, recovering a subsidy from the nondiscounted customers in the class receiving the discount may just push more of those customers into distress. Hence, the most reasonable manner of recovering a subsidy will vary: If the residential class is mostly affluent, with small pockets of poverty, dealing with a low-income discount entirely through rate design in the residential class may be appropriate. But if most of the residential class is in a tenuous financial condition, but the commercial and industrial classes in the territory are thriving, spreading the subsidy costs over all classes may be most appropriate, with a net credit to the residential class and charges to other classes, perhaps on an energy basis.

186 For example, Nevada has a requirement that certain irrigators receive low rates: "IS-2 is a subsidized rate that NV Energy charges eligible agricultural customers who agree to interruptible irrigation pump service during certain situations. This service is applicable to electricity used solely to pump water to irrigate land for agricultural purposes. Agricultural purposes include growing crops, raising livestock or for other agricultural uses which involve production for sale, and which do not change the form of the agricultural product pursuant to NRS 587.290" (NV Energy, n.d.).

187 Low-income subsidies may be motivated by a combination of social concerns (such as reducing the burdens on needy customers and avoiding health-related problems of customers unable to heat or cool their homes), utility practicality (reducing bad debt and collection expenses) and cost causation. Low-income consumers are typically low-use customers and may tend to have less temperature-sensitive load that drives utility system peaks. Depending on the composition of the low-income population, they may also be at home in a different pattern than higher-income customers. A time-differentiated cost study may illuminate these differences.

188 For example, California Public Utilities Code § 327(a)(7) requires that the low-income electric rate for its IOUs be allocated by equal cents per kWh to all customers except recipients of the low-income rate and street lighting customers.

189 For example, a pro forma adjustment to revenue for each class (positive to the residential class; negative to other classes) would spread the subsidy across all the classes that the regulator concludes should contribute to this service.

# 15. Revenues and Offsets in Embedded Cost of Service Studies

## 15.1 Off-System Sales Revenues

Some retail cost of service studies treat wholesale sales as a separate class and allocate costs to the off-system customers. The cost of service study does not necessarily lead to any change in the off-system customers' charges (which are typically set by contracts, markets or FERC) but does help the regulator determine what share of the revenue requirement not recovered by FERC-regulated sales should be borne by each retail class. Alternatively, many utilities allocate all their costs to the retail classes and credit the export revenues back to the retail classes.[190]

In the latter approach, utilities sometimes allocate wholesale revenues to classes in proportion to their allocation of generation costs. Under this type of allocator, the greater the rate class's demand and usage, the greater its share of the off-system sales revenue. The problem with this approach is that some classes (e.g., industrials) use most of the generation capacity allocated to them throughout the year, while other classes typically pay for capacity they use in their peak season but which is available for sale in other seasons. Off-system sales revenues depend not only on the retail customers' financial support of the resources (including generating capacity) from which off-system sales are made but also on the extent to which class load shapes leave resources available to make those sales.

A more appropriate allocator would reward a class for having lower demand and usage, perhaps on a monthly basis, thereby leaving generation (and transmission) capacity available to support the off-system sales. In other words, the revenue from off-system sales should reflect classes' contribution to the availability of capacity to make the sales.[191]

## 15.2 Customer Advances and Contributions in Aid of Construction

As discussed in Section 11.2, most utilities charge new customers or new major loads for expansion of the delivery system, at least in some circumstances. Utilities frequently require customer advances for construction costs when they are asked to build a facility to accommodate subsequent load growth (e.g., to connect a subdivision or commercial development before some or perhaps any of the units are built and sold). The utility requires the advance to transfer to the developer the risk that the load will never materialize, or that load will grow more slowly than expected. As the load materializes, the advances are refunded to the developer. Those advances provide capital to the utility and generally are treated as a reduction of rate base; that cost reduction should be directly assigned to the customer classes for whom the advances were made.

Contributions in aid of construction are similar to customer advances but are applied in situations in which the utility does not expect the incremental net revenues from the load to cover the entire cost of the expansion. The contributions are thus a permanent payment to the utility, offsetting part of the capital cost. Contributions in aid of construction should be treated similarly to customer advances, allocated as

190 The same approach is possible with retail customers whose rates are fixed under multiyear contracts. Off-system sales revenues may vary considerably, based on market conditions, and are therefore often included in a fuel adjustment clause or similar rider between rate cases, while the base allocation is typically established in a general rate case.

191 MidAmerican Energy in Iowa proposed an hourly cost allocation method for capacity and energy in a recent case but also argued that if the Iowa Utilities Board were to use its traditional "average and excess demand" method instead, off-system sales margins should be allocated by excess demand, not by energy. "MidAmerican believes it is more appropriate to allocate wholesale margins (revenues less fuel costs) based on the excess demand component of the [average and excess] allocator, as it is from excess generation capacity that wholesale sales can be made" (Rea, 2013, p. 19).

rate base reductions for the class for which the contributions were made. Where that is not possible, they should be applied as realistically as possible to offset the rate base for the types of facilities for which the contributions were collected.

As noted in Section 12.2, customer deposits that offset rate base should be allocated consistently with uncollectible accounts expenses and late payment revenues.

## 15.3 Other Revenues and Miscellaneous Offsets

The treatment of other operating revenues affects customer class allocation. Some cost of service studies allocate all these revenues proportionally to a broad-based factor such as base rate revenue. Others do a more granular analysis. The granular analysis is preferable analytically because it is closer to the basis for the revenues.[192] There are several types of other operating revenue. Three of the largest are:

- Late payment revenues.
- Revenues for auxiliary tariffed services.
- Rents and pole attachment revenues.

As discussed in Section 12.2 earlier, late payment revenues need to be treated consistently with uncollectible accounts expenses and customer deposits.

Auxiliary tariffed service revenues result from directly charging customers for certain actions that customers take. The large majority of tariffed revenues result from items such as service establishment charges, charges for reconnection after disconnection, field collection charges and returned check charges. These revenues should not be allocated broadly because the revenues are predominantly paid by residential customers and the costs that these revenues reimburse are predominantly in customer-related accounts that are largely assigned to residential customers (accounts 586, 587, 901 to 903 and 905). These revenues should be directly assigned to the customer class that pays them or (if that is not possible) allocated in proportion to customer accounts expenses excluding uncollectibles.

Tariffed service charges for costs associated with opting out of AMI should be allocated in the same way as the costs of AMI opt-outs (as discussed in Section 12.1).

Rents should be allocated to the function causing the rents (distribution lines, office buildings, etc.). In particular, pole attachment revenues from cable and telecommunications companies should be allocated in proportion to poles.

192 For example, assigning revenues from service establishment charges based on total base rate revenue would result in large customers, who rarely move, receiving revenue as if they had moved many times in a single year.

# 16. Differential Treatment of New Resources and New Loads

In some situations, regulators have treated new resources or new loads using considerations that do not fit neatly into the embedded cost of service study framework. In particular, equity may sometimes be improved by reflecting the history and projections of class loads. However, there are risks in adopting such an approach, particularly within customer classes. Regulators should be careful to ensure adoption of such techniques is not arbitrary or discriminatory and is grounded in solid reasoning.

These differential treatment techniques are sometimes referred to as incremental cost of service studies[193] and can be conceptualized as either applying two different embedded cost techniques or combining an embedded cost technique with a marginal cost technique. In either case, the defining characteristic of these methods is the recognition that the costs associated with load growth in the recent past or the relatively near future, which typically might be several years, are being driven by a specific class or subclass of customers.

Incremental cost considerations are sometimes used to address a special circumstance that justifies differential treatment for particular classes or subclasses of customers within the context of an embedded cost study. Examples include:

- Allocating legacy low-cost generation resources to classes in proportion to their contribution to loads in a past year (perhaps the last year in which those resources were adequate to serve load), with the higher incremental costs of newer generation allocated to classes in proportion to their load growth since that base year.
- Setting the revenue requirements for selected classes or subclasses at levels below the general cost allocation but higher than near-term incremental costs; for example, in determining how to apportion the cost burden of economic development programs or low-income assistance programs.
- Developing desired end uses that may require preferential rates in the short term (e.g., electric vehicles or docked ships that would otherwise be burning oil) to provide a societal benefit or stimulate a desirable market.

In most cases, the differential treatment is intended to protect customers in the other classes from higher costs of new resources or from bearing a larger share of legacy costs.

## 16.1 Identifying a Role for Differential Treatment

A study with differential treatment typically looks at the costs the system will incur within a relatively short time horizon to serve new load or retain existing load. The costs that may differ between the legacy loads and resources and incremental loads and resources include the variable costs of existing generation resources and the costs of new supply resources, transmission projects and distribution upgrades.[194] In each case, inequities or inefficiencies arise because costs do not scale proportionally to the drivers, such as load. If the utility has committed generation resources, with low variable costs, in excess of its requirements and has overbuilt most of its transmission and distribution circuits, incremental costs will tend to be below average costs.[195] In contrast, in a period of tight supply, the near-term costs of running expensive generation and adding generation, transmission and distribution resources may be higher than embedded costs.

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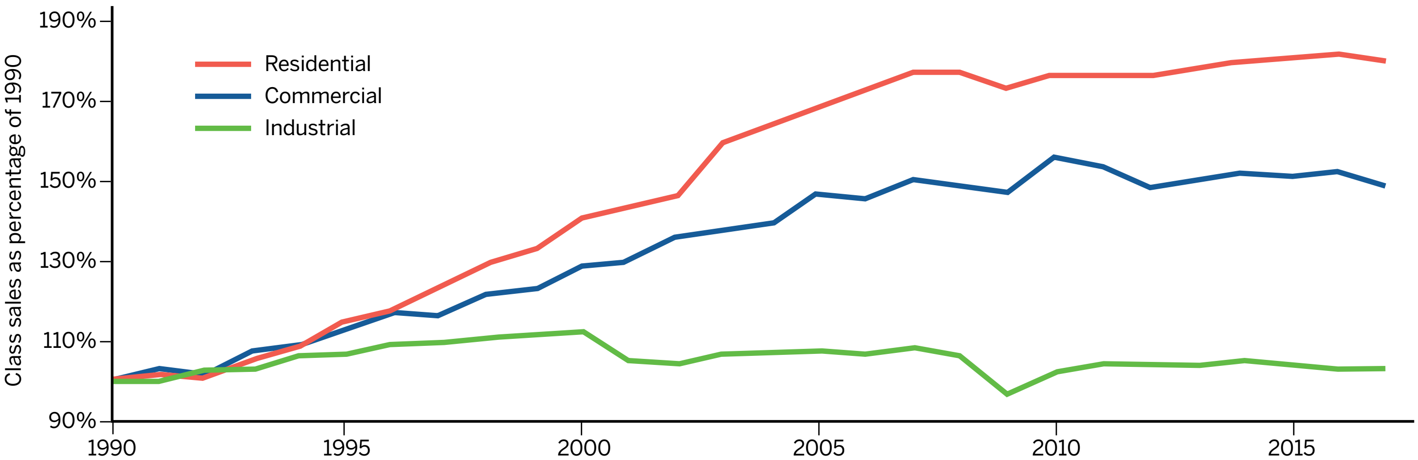
193 The term "incremental cost of service study" in this case is not used in the same sense as a marginal cost of service study, where the marginal impact of load patterns is measured.

194 In principle, there could be similar differences in the costs of some customer service elements, such as between an existing billing system that would be adequate indefinitely for the existing accounts and an expensive new system that would be required if the utility adds accounts.

195 Surplus capacity does not always imply that incremental costs are below average costs. If the utility can save money by selling surplus generation resources or shutting them down, the incremental cost of retaining or increasing load may be as high as the embedded costs or nearly so.

**Figure 43. US load growth by customer class since 1990**




Data source: U.S. Energy Information Administration. *Form EIA-861M Sales and Revenue: 1990-Current*

In some cases, growth has profound impacts on system costs, and special consideration of differential growth rates may be important to the regulator. Load growth at certain hours may be beneficial, while load growth at other hours may be problematic, requiring new resources. Those facilities may be more expensive than the existing equivalents due to any of the following:

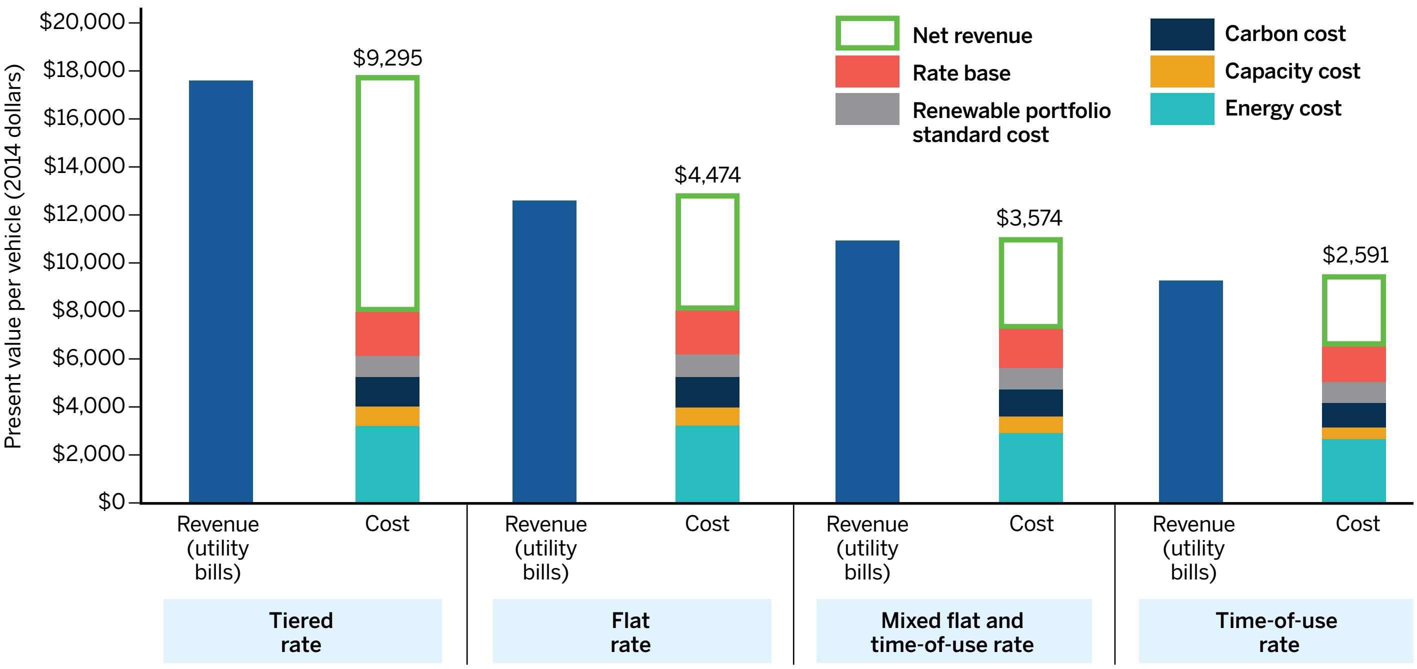
- Inflation: Equipment built 20 years ago will usually be less expensive than the same equipment installed today; buying new sites for generation or substations may be many times the embedded costs of sites purchased in the 1950s.
- Location: Existing generation may be located near load centers, while new generation may be required to locate much farther away; the existing distribution system may be relatively dense, while the new loads require long line extensions.
- Regulatory standards: The utility may be required to locate new lines underground;[196] environmental standards for routing, construction and emissions are often more restrictive for new resources than existing ones.
- Exhaustion of favorable opportunities: A utility may have relied historically on low-cost hydro, while its new resources may be much more expensive; ideal sites for wind power tend to be the first ones developed, while less favorable sites are generally developed later.
- The particular needs of the growing loads, such as higher reliability or power quality, or three-phase service in areas with mostly single-phase service.

Most traditional embedded and marginal cost studies do not take differential growth into account. U.S. residential loads grew about 50% from 1990 to the 2008 recession and not at all since; commercial loads grew about 80% up to the recession and slightly since; and total industrial electricity consumption grew slowly to about 2000 and has declined slowly since, as shown in Figure 43 (U.S. Energy Information Administration, n.d.-b). Load growth patterns for individual utilities may be much more disparate, both among customer classes and between clearly distinguishable subclasses (such as urban and rural, small markets and big-box stores, or farms and mines).

Where incremental costs are much higher than embedded costs, the difference may be assigned to classes in proportion to their growth. If it is a subset of a class that is growing quickly, there may be a rationale for adopting separate tariffs or riders for new customers within that class or for an identifiable subgroup contributing to higher costs (e.g., large vacation homes or data centers). The correct answer in some cases is the creation of a new customer class with separate load and cost characteristics. Beyond cost allocation, the incremental costs may be reflected in rate design and connection fees. For

196 Undergrounding may also be required by the difficulty in finding room for overhead transmission through built-up areas.

**Figure 44. Estimated revenue and cost from serving additional electric vehicle load**




Source: Energy and Environmental Economics. (2014). *California Transportation Electrification Assessment — Phase 2: Grid Impacts*

example, higher costs may also be allocated to the entire class but collected through a rate element (e.g., consumption over twice the monthly average) that aligns well with the customers causing the additional costs.

In some situations, load growth can reduce system average costs, at least temporarily, by spreading embedded costs over more units of sales. Regulators sometimes reduce rates to a special class or particular customers who will demonstrably generate more revenue with the lower rates, such as with economic development and load retention rates. At the present time, this may apply to beneficial electrification of transportation. Figure 44 shows a calculation of how additional electric vehicle load would generate additional net revenue, thus creating opportunity to benefit new EV users and existing consumers (Energy and Environmental Economics, 2014).

Some generation resources, such as federal hydropower entitlements, are made available to utilities by statute to serve particular loads, such as residential customers. Many regulators allocate those benefits to the classes whose entitlement to the power makes it available to the utility.[197]

## 16.2 Illustrative and Actual Examples of Differential Treatment

Table 37 on the next page shows an illustrative incremental cost study. In this simplified example, costs are rising; many are directly related to growth, but some are not. Costs relating to growth are assigned to the classes in proportion to their growth. Costs not related to growth are assigned based on each class share of current usage. The result, where both classes start at the same usage level but one grows four times as quickly as the other, is that the growth-related costs are assigned to the growing class, increasing its revenue responsibility if its costs are greater than current rates or decreasing its responsibility if its costs are lower than current rates.

In this illustration, both classes had equal rates in the previous rate proceeding. But costs have risen for both nongrowth categories (inflation) and growth categories (new resources and new distribution capacity). After application of an incremental cost study, the slow-growing class is assigned a rate averaging

197 Those benefits are often reflected in rate design by development of a lower first energy block to ensure that each eligible customer gets an appropriate share of the benefit.

14 cents per kWh, while the fast-growing class is assigned an average of 17 cents per kWh. In the opposite situation, where incremental costs are lower than average costs, the growing class might be assigned lower costs.

**Table 37. Illustrative cost study with differential treatment of new resources**

| | Total | Residential | Commercial and industrial |
|---|---|---|---|
| **Revenues at previous usage** | $200,000,000 | $100,000,000 | $100,000,000 |
| **Previous usage (MWhs)** | 2,000,000 | 1,000,000 | 1,000,000 |
| **Current rates per kWh** | $0.10 | $0.10 | $0.10 |
| **Usage** | | | |
| In current rate period (MWhs) | 2,250,000 | 1,050,000 | 1,200,000 |
| Growth from previous (MWhs) | 250,000 | 50,000 | 200,000 |
| Class share of growth | | 20% | 80% |
| Class share of current | | 46.7% | 53.3% |
| **Growth-related costs** | $100,000,000 | $20,000,000 | $80,000,000 |
| **Nongrowth costs** | $50,000,000 | $23,335,000 | $26,667,000 |
| **All increased costs** | $150,000,000 | $43,335,000 | $106,667,000 |
| **Total revenue requirement** | $350,000,000 | $143,335,000 | $206,667,000 |
| **Usage in current rate period (MWhs)** | | 1,050,000 | 1,200,000 |
| **New rates per kWh** | | $0.14 | $0.17 |

Note: Numbers may not add up to total because of rounding.

## 16.2.1 Real-World Examples

This section describes specific applications of differential treatment in cost allocation to illustrate the range of concepts.

### Seattle City Light 1980 Cost Allocation

In 1980, Seattle City Light, a municipal utility, was experiencing rapid growth in commercial loads with stagnant to declining industrial loads. It recognized that continued growth would require it to commit to new nuclear or coal plants with incremental power costs much higher than the embedded hydro resources. Average rates were about 2 cents per kWh, while just the expected cost of new generation resources was about five times that level.

Even without the new resources, Seattle City Light required a rate increase and developed an interclass cost allocation method along the following lines:[198]

- Starting with historical-year sales by class and prior year revenues by class.
- Assigning the costs related to growth in proportion to the sales to each class, using forecast sales and expected long-term resource acquisition costs.
- Apportioning the residual revenue requirement increase on a uniform basis to all customer classes.

This approach resulted in an average increase in residential rates, an above-average rate increase to commercial customers and a below-average rate increase to industrial customers. It achieved the stated equity goal of charging more to the fastest-growing customer class — that is, the class that was driving the lion's share of the incremental costs.

### Vermont Hydro Allocation

The state of Vermont receives an allocation of low-cost power from the Niagara and St. Lawrence hydroelectric facilities owned by the New York Power Authority, pursuant to a requirement in statute that allowed construction of the plants, to provide power to Vermont.[199] The Burlington Electric Department allocates this power to the residential customer class.[200] Other classes do not benefit from this resource. This is a method of ensuring that limited low-cost

198 One of the authors of this manual, Jim Lazar, participated in this proceeding on behalf of an intervenor.

199 "In order to assure that at least 50 per centum of the project power shall be available for sale and distribution primarily for the benefit of the people as consumers, particularly domestic and rural consumers, to whom such power shall be made available at the lowest rates reasonably possible" (Niagara Redevelopment Act, Pub. L. No.85-159, 16 U.S.C. § 836[b][1]). NYPA was required to provide a portion of the power to public bodies and co-ops in neighboring states (16 U.S.C. § 836[b][1]). Thus, the resources were made available to the Burlington Electric Department for the purpose of benefiting residential customers.

200 The Burlington Electric Department also uses that allocation to create an inclining block rate design consisting of a customer charge to cover billing, collection and other customer-specific costs; an initial block priced at the New York Power Authority cost plus average T&D costs; and a tail block that pays for other generation resources plus average T&D costs. See Burlington Electric Department (2019).

resources are equitably allocated to the customers for whom the New York Power Authority provides the power and that all customers share the cost of incremental resources needed to serve demand in excess of incremental usage.[201]

### Northwest Power Act — New Large Single Loads

The Pacific Northwest Electric Power Planning and Conservation Act of 1980 provided, among other things, for division of the economic benefits of the federal Columbia River power system among various customer groups and rate pools (Pub. L. No. 96-501; 16 U.S.C. § 839 et seq.). The act set forth a specific mechanism for the Bonneville Power Administration to charge a price based on new resources to "new large single loads" (discrete load increments of 10 average MWs or 87,600 MWhs per year, such as might be experienced if a new oil refinery were built). This provision was intended to protect existing consumers from rate increases that could result from new very large loads attracted by the low average generation costs in the region, in a period in which new resources were very expensive. Table 38 shows average rates for Bonneville Power Administration by category for recent years, including a higher rate for new resources (Bonneville Power Administration, n.d.).[202]

**Table 38. Bonneville Power Administration rate summary, October 2017 to September 2019**

| Rate category | Average rates per MWh |
|---|---|
| **Priority firm public utility average** | $36.96 |
| **Priority firm public utility Tier 1** | $35.57 |
| **Priority firm – IOU residential load** | $61.86 |
| **Industrial power** | $43.51 |
| **New resources** | $78.95 |

Source: Bonneville Power Administration. *Current Power Rates*

### Nova Scotia Power Load Retention and Economic Development Rates

In 2011, falling global demand for paper resulted in the bankruptcy and shutdown of two paper mills that were Nova Scotia Power's largest customers, which accounted for about 20% of its sales and 12% of its revenues. The mills had been major employers, both directly and as purchasers of wood harvested from forests in the province. A buyer emerged for the larger of those facilities, contingent on a variety of supportive policies from the provincial and federal governments, including favorable tax treatment and rates.

Nova Scotia Power proposed and the Nova Scotia Utility and Review Board approved (with modifications) a load retention rate that would charge the mill hourly marginal fuel and purchased power costs (including opportunity costs from lost exports), plus administrative charges and mill rates to cover variable O&M, variable capital expenditures and a contribution to capital investments and long-term O&M. The load would be entirely interruptible, and the utility committed to excluding the mill's load from its planning and commitment decisions (Nova Scotia Utility and Review Board, 2012).

The determination of Nova Scotia Power's hourly marginal costs proved to be more difficult than expected.[203] Nonetheless, the rate design succeeded in attracting the investment necessary to restart and retain the mill as an employer while producing some contribution to Nova Scotia Power's embedded costs. The load retention tariff expires in 2020, at which time the mill may switch to a firm rate or negotiate a new load retention tariff.[204]

### Chelan County Public Utility District Bitcoin Rate

The creation of bitcoin cryptocurrency units requires energy-intensive mathematical computations called mining. To limit the cost of their operations, bitcoin "miners" have sought locations with low-priced electricity. Those operations

201 This same concept has been the foundation of inclining block rates in Washington state and Indonesia.

202 The average rates subsume a variety of fixed and variable charges.

203 Nova Scotia Power was not part of an energy market and had limited connections to its only neighboring utility (NB Power, which is also not part of an energy market), and its marginal generation resources are coal plants with long commitment horizons (Rudkevich, Hornby and Luckow, 2014).

204 The Nova Scotia Power system will operate differently after 2020, when it is expected to have access to large amounts of Newfoundland hydro energy and operate under stricter carbon emissions standards. Any new load retention tariff would need to reflect those changes.

typically require very large amounts of power but have few on-site employees and little local economic benefit. One of these locations is Chelan County in Washington state, where the local public utility district owns two very large dams on the Columbia River and has industrial rates about one-fourth of the national average.[205]

Chelan County Public Utility District's existing low-cost resource is fully obligated to a combination of local retail use and long-term contract sales. The contract sales prices are above the average retail rates, bringing significant revenue to fund public infrastructure in the county, including a world-class parks network. When the district received applications for service from bitcoin miners, it decided that this high-density load growth would not be in the public interest, declared a moratorium on new connections and developed a tariff designed to ensure that any growth of this type of load would not adversely affect other consumers or the local economy (Chelan County Public Utility District, 2018). This tariff is geographically differentiated, to recognize areas where transmission and distribution capacity are available, and includes:

- Payment in a one-time charge of transmission and distribution system costs to serve large new loads.
- A price for electricity, tied to (generally higher) regional wholesale market prices, not Chelan County Public Utility District system costs.
- Severe penalties for excess usage that could threaten system reliability.

205 The Chelan County Public Utility District rate for primary industrial customers up to 5 MWs with an 80% load factor is 1.91 cents per kWh (Chelan County Public Utility District, n.d.). The average U.S. industrial price was 6.88 cents per kWh in 2017 (U.S. Energy Information Administration, 2018, Table 5.c).

# 17. Future of Embedded Cost Allocation

Change is inevitable as the electric industry adapts to new technology. Part III of this manual, on embedded cost of service studies, has attempted to address many common situations the cost analyst will face in determining an equitable allocation of costs among customer classes. But new technologies and changing loads will dictate new issues and perhaps new methods.

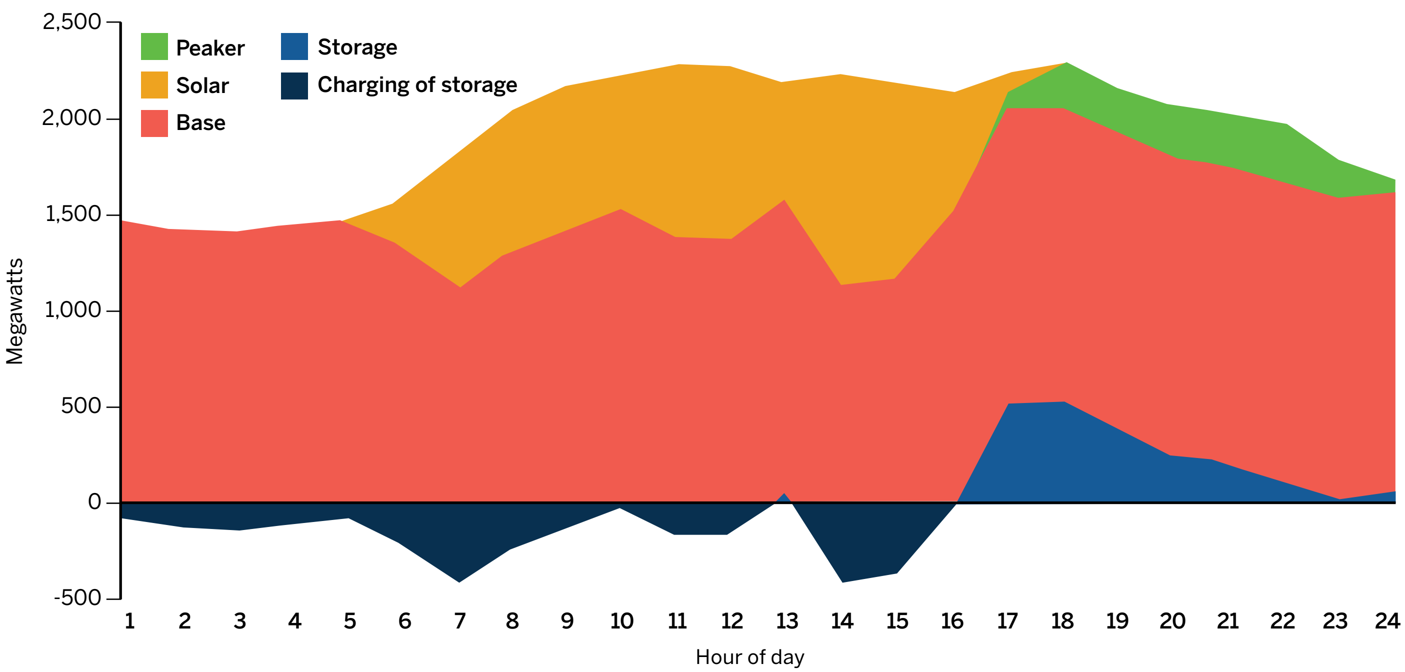
Historically, power has flowed from central generators, through transmission, to primary distribution and then secondary distribution. Customers served at the transmission level have not paid for distribution, and those served at primary have not paid for line transformers or secondary lines. This situation is beginning to change. In some places, the development of distributed solar capacity already causes power to flow from secondary to primary and even onto the transmission system. At some point, all customers may receive service through all levels of the delivery system, requiring a substantial rethinking of the allocation of distribution costs.

In addition to the increased complexity of system operations, utilities have more data about system operations and customer loads than they had a few decades ago. As the costs of electronics decline, more data will become available to more utilities. Thus, methods that were the best available in the 1980s can now (or soon) be superseded by more accurate and realistic allocations. Computations that would have been unwieldy on the computers of the 1980s are trivial today.

For example, as utilities acquire data on the hourly load of each class, many costs can be allocated on an hourly basis, rather than on such summary values as annual energy use and contribution to a few peak load hours. The costs of baseload generation resources (nuclear, biomass, geothermal) may be assigned to all hours; costs of wind and solar resources to the hours they provide service; storage to the hours in which it exports energy and provides other benefits;[206] and demand response costs to the hours these resources are deployed or the hours in which they reduce costs by supplying operating reserves. In a sense, this is an evolution and refinement of the base-intermediate-peak traditional method, described in Section 9.1.

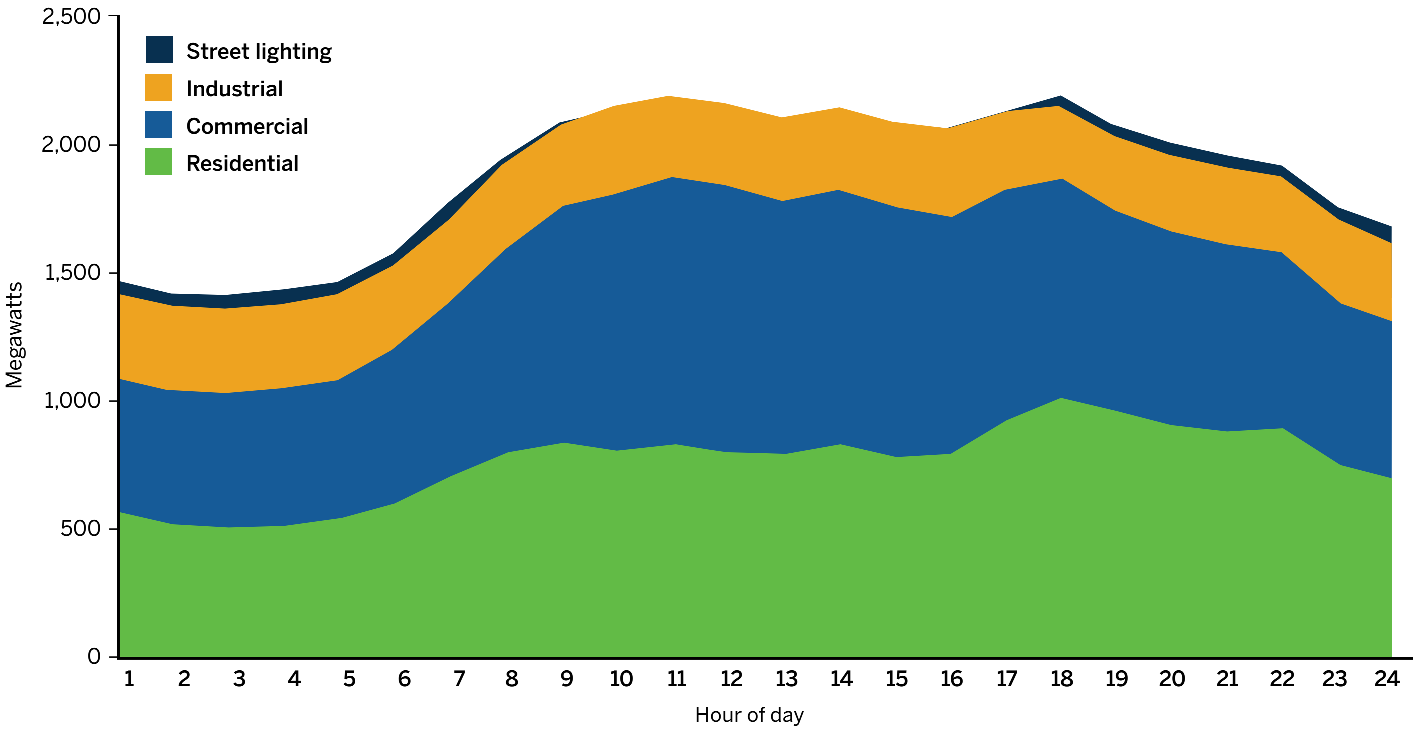
To illustrate this approach, Figure 45 provides a day's

**Figure 45. Daily dispatch for illustrative hourly allocation example**




206 Among other things, charging storage in hours with low net loads will raise minimum load levels and reduce ramp rates, benefiting the hours in which net load rises rapidly.

**Figure 46. Class loads for illustrative hourly allocation example**




worth of hourly dispatch of four resources: a baseload resource (perhaps nuclear), solar, a peaker (perhaps a combustion turbine) and storage (both as charging load below the axis and generation above the line). In this example, the storage charges from excess base capacity in the early morning and then from solar, and discharges in the evening to replace the waning solar. The actual application of hourly allocation would include 8,760 hours from an actual or typical year, with a wide range of load levels, availability of the base resource and solar output patterns.

Figure 46 provides hourly energy requirements by class (including losses) for the same day as in Figure 45.

Table 39 on the next page provides two types of data from Figure 45 and Figure 46: each class's share of the load in each hour, and the portion of each resource's daily generation that occurs in the hour.

The generation cost allocation for a class would be:

$$\sum_{r,h} L_h \times S_{r,h} \times C_r$$

Where $L_h$ = class share of load in hour *h*

$S_{r,h}$ = share of resource *r* output that occurred in hour *h*

$C_r$ = cost of resource (in this example, for the day)

Table 40 shows the result of this computation for the data in Table 39. The lighting class, for example, would pay for 1.8% of the base resource, 2.2% of the peakers and just 0.6% of the solar. Table 40 also shows each class's share of total load, for reference.

**Table 39. Hourly class load share and resource output**

| | Class share of load | | | | Resource output: Percentage occurring by hour | | | |
|---|---|---|---|---|---|---|---|---|
| Hour | Residential | Commercial | Industrial | Street lighting | Base | Peaking | Solar | Storage |
| 1 | 39.0% | 35.3% | 22.5% | 3.2% | 4% | 0% | 0% | 0% |
| 2 | 37.0% | 36.2% | 23.5% | 3.3% | 4% | 0% | 0% | 0% |
| 3 | 36.4% | 36.7% | 23.5% | 3.4% | 4% | 0% | 0% | 0% |
| 4 | 36.7% | 37.0% | 23.1% | 3.3% | 4% | 0% | 0% | 0% |
| 5 | 37.5% | 36.6% | 22.7% | 3.2% | 4% | 0% | 0% | 0% |
| 6 | 38.4% | 37.2% | 21.4% | 3.0% | 4% | 0% | 3% | 0% |
| 7 | 39.7% | 37.1% | 20.6% | 2.6% | 4% | 0% | 8% | 0% |
| 8 | 39.8% | 39.2% | 19.5% | 1.6% | 4% | 0% | 9% | 0% |
| 9 | 38.8% | 42.6% | 18.4% | 0.2% | 4% | 0% | 9% | 0% |
| 10 | 36.7% | 44.8% | 18.2% | 0.2% | 4% | 0% | 8% | 0% |
| 11 | 36.6% | 45.1% | 18.1% | 0.2% | 4% | 0% | 11% | 0% |
| 12 | 35.9% | 45.8% | 18.1% | 0.2% | 4% | 0% | 10% | 0% |
| 13 | 36.7% | 44.8% | 18.3% | 0.2% | 4% | 0% | 7% | 1% |
| 14 | 37.5% | 44.0% | 18.2% | 0.2% | 4% | 0% | 13% | 0% |
| 15 | 36.3% | 44.7% | 18.8% | 0.2% | 4% | 0% | 12% | 0% |
| 16 | 37.4% | 43.5% | 18.8% | 0.2% | 4% | 0% | 7% | 0% |
| 17 | 41.5% | 40.6% | 17.4% | 0.4% | 4% | 5% | 1% | 25% |
| 18 | 44.7% | 37.3% | 16.1% | 2.0% | 4% | 13% | 0% | 25% |
| 19 | 45.2% | 35.8% | 16.8% | 2.2% | 4% | 13% | 0% | 18% |
| 20 | 44.2% | 36.1% | 17.4% | 2.3% | 4% | 15% | 0% | 12% |
| 21 | 44.4% | 35.4% | 17.8% | 2.3% | 4% | 15% | 0% | 10% |
| 22 | 45.9% | 33.8% | 17.9% | 2.4% | 4% | 19% | 0% | 5% |
| 23 | 42.8% | 35.1% | 19.4% | 2.6% | 4% | 12% | 0% | 1% |
| 24 | 41.6% | 35.5% | 20.1% | 2.8% | 4% | 6% | 0% | 3% |
| All hours | 39.7% | 39.6% | 19.1% | 1.6% | 100% | 100% | 100% | 100% |

Note: Percentages may not add up to 100 because of rounding.

**Table 40. Class shares of resource cost responsibilities and load**

| | Residential | Secondary commercial | Primary industrial | Street lighting |
|---|---|---|---|---|
| **Resource type** | | | | |
| Base | 39.6% | 39.2% | 19.4% | 1.8% |
| Peaker | 44.3% | 35.8% | 17.7% | 2.2% |
| Solar | 37.5% | 43.1% | 18.7% | 0.6% |
| Storage | 43.8% | 37.4% | 17.2% | 1.7% |
| **Class share of total load** | 39.7% | 39.6% | 19.1% | 1.6% |

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# Part IV:

# Marginal Cost of Service Studies

# 18. Theory of Marginal Cost Allocation and Pricing

The fundamental principle of marginal cost pricing is that economic efficiency is served when prices reflect current or future costs — that is, the true value of the resources being used to serve customers' loads — rather than historical embedded costs. This is a strong underpinning that most analysts agree on, but there are serious theoretical and computational complications associated with the development of marginal costs.

Economic efficiency is served when prices reflect the true value of the resources being used to serve customers' loads.

Marginal cost studies start from a similar functionalization as embedded cost studies: generation, transmission, distribution. However, the data used are not at all the same as those used in an embedded cost of service study. The typical marginal cost of service study requires detailed hourly data on loads by customer class, marginal energy costs and measures of system reliability (loss-of-energy expectation, peak capacity allocation factor, probability of peak, etc.), as well as multiyear data on loads and investments for the transmission and distribution system.

As will be discussed below with specific examples and applications, the time horizon of marginal cost studies and even of individual components within studies can vary. Marginal costs can be measured in:

- The short run, as with energy costs measured for one to three years, and all capital assets kept constant.
- Intermediate periods ranging from six years (the length of two typical general rate cases for many utilities) to 15 years (often used for analysis of T&D capital investments).
- The long term, such as with **long-run incremental costs** for the entire generation function; long-run generation capacity costs based on equilibrium conditions; and the rental of customer equipment in some marginal customer cost studies. The longest possible analysis would be a total service long-run incremental cost study where an optimal system is costed out.

At one extreme, a true short-run marginal cost study will measure only a tiny fraction of the cost of service that varies from hour to hour with usage and holds all other aspects of the system constant. At the other extreme, a TSLRIC study measures the cost of replacing today's power system with a new optimally designed and sized system that uses the newest technology. In between is a range of alternatives, many of which have been used in states like Maine, New York, Montana, Oregon and California to determine revenue allocation among classes. The major conceptual issue in these studies is using very short-run metrics for energy cost and longer-term metrics for capital costs (generation, transmission and distribution capacity and customer connection costs). Many studies use these mixed time horizons, but this is an error that should be avoided.

Marginal cost pricing generally is not connected to the utility's revenue requirement, except to some extent in restructured generation markets (where the costs are not subject to traditional cost of service regulation). The calculated marginal costs may be greater or less than the allowed revenue requirement, which is normally computed on an accounting or embedded cost basis. It is only happenstance if marginal costs and embedded costs produce the same revenue.

There is also no necessary connection between marginal cost pricing and cost allocation. To summarize the material discussed in more depth below, in its simplest hypothetical form, a marginal cost study computes marginal costs for different elements of service, and these are multiplied by the determinants for each class. This produces a class marginal cost revenue requirement and, when combined with other classes, a system MCRR. This is then reconciled with the allowed revenue requirement to determine revenue allocation by class. This part of this manual provides some examples of marginal cost studies and the revenue allocation resulting from them.

A second important concept related to marginal cost pricing comes from the theory of general equilibrium: If costs are in equilibrium, short-run marginal costs equal long-run marginal costs. That is, to get one more unit from existing resources would require operating resources with high variable costs, at a cost equal to the cost of both building and operating newer, cheaper resources. However, it is hard to apply this theory in practice because developing and quantifying a system in equilibrium is extremely difficult. Until recently, assets tended to be developed in large sizes relative to the utility's overall system needs, rendering equilibrium conditions unlikely. Equilibrium is also impossible in the real world, for three main reasons. First, loads and fuel prices can never be forecast exactly (and often cannot be forecast even closely). Technology also changes, and the use of specific resources ends up changing. Finally, long lead times to construct various resources (particularly large power plants and transmission lines) can exacerbate the consequences of forecasting errors.

As a result, the marginal cost methods used today, such as those developed by National Economic Research Associates (now NERA Economic Consulting) — discussed in considerably more detail throughout Part IV — do not reflect equilibrium conditions. Moreover, with the current configuration of the electric system and changes over time, the trend has been toward overbuilding, so generation marginal cost ends up systematically below average cost, with ramifications for class allocation. In addition, as previously implemented in many jurisdictions, the definitions of marginal cost have mixed short-term and long-term elements in ways that are theoretically inconsistent.

## 18.1 Development of Marginal Cost of Service Studies

The most common method used in jurisdictions relying on marginal costs for allocation purposes was developed by Alfred Kahn and colleagues at NERA in the late 1970s.[207]

The Kahn/NERA method (referred to as the NERA method in this manual because that is the term most analysts and practitioners use) is the predominant method that current marginal cost analysts use. Some entities, such as Oregon, use a long-run marginal cost method for generation, and other states and analysts have proposed changes to specific components of the NERA method. Nevertheless, the NERA method, whatever its benefits and detriments, is the starting point for most current marginal cost of service study analysis, and marginal cost of service study analysts have identified fewer alternative methods than have embedded cost of service study analysts.

Another practical consideration in analyzing marginal cost methods is that very few states are marginal cost jurisdictions. In particular, California, Nevada and Oregon calculate marginal costs for generation and other functions; Maine and New York have deregulated generation but use marginal costs for distribution. Thus, many examples in the remaining discussion come from a relatively small number of jurisdictions.

The NERA methodology uses:

- Long-term customer costs based on the cost of renting new customer connection equipment using the current technology.
- Intermediate-term transmission and shared distribution costs based on an analysis of additions made to serve new capacity but not to increase reliability or replace existing capacity to continue to serve load, measured over 10 to 15 years.
- Generation capacity costs that tend toward a longer term based on new construction.[208]
- Usually relatively short-term marginal energy costs (one to six years).

207 National Economic Research Associates developed a series of papers on the topic. The most critical for this manual are *A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States* (1977a) and *How to Quantify Marginal Costs* (1977b).

208 Some utilities and consumer advocates have used shorter-term generation capacity costs. Consumer advocates often chose shorter-term generation costs when revenue allocation was done by function rather than in total. See Section 19.3.

One of the key concepts developed through this work was the real economic carrying charge. A RECC takes the revenue requirements or costs of a resource and reshapes them to reflect a stream of costs that increases with inflation and has the same present value as the revenue requirements. Inputs to a RECC are the same as those used for utility revenue requirements. They include the capital structure and cost of capital, a discount rate, income tax parameters (rates, depreciation and whether specific tax differences are normalized or flowed through), book depreciable life and costs of property taxes and insurance. The RECC is not unique to this method but can be used in conjunction with other methods, such as long-run incremental cost of generation (see Section 19.1) or total service long-run incremental cost (Section 25.1).

Analytically, the RECC also reflects the value associated with deferring a project from one year to the next and can be used to place projects with different useful lives on a common footing. The RECC is lower than the utility's nominal levelized cost of capital for a given type of plant and lower than the early year revenue requirements calculated traditionally for such a plant. A further discussion of the RECC, with a specific example, is in Appendix B.

The mismatch of long-run and short-run marginal costs among cost components is particularly problematic in the NERA method. If system costs are allocated using the total measurement of generation costs based on relatively low shorter-run costs for energy and generation (that do not consider the value of capital substituting for energy over time) and much longer-term costs for the distribution and customer functions, the study will mathematically give too much weight to distribution costs in a marginal cost study, to the detriment of small customers. Analysts have used a number of methods to ameliorate or counteract this mismatch. These methods are briefly identified here but discussed in more detail in the sections noted.

- Developing a longer time horizon for generation costs (see Chapter 19 and Section 25.1). Various methods include:
  - Extending the time horizon for marginal energy costs and including carbon dioxide reductions and renewable costs as adders to short-run marginal energy costs.
  - Using long-run incremental costs, including full costs of new construction of generation.
  - Applying the new paradigm of long-run incremental cost analysis, at least for generation, explicitly to include the energy transition to renewables for generation and storage and demand response for capacity.
- Using short-run customer costs based on the direct costs of hooking up new customers as a better match with short-run energy costs (see Chapter 21).
- Ignoring joint and common costs, reducing long-run A&G costs that are assigned to functions other than energy (see Chapter 22).
- Reconciling on a functionalized basis (generation, transmission and distribution by the marginal costs of those functions) instead of on a total cost basis (see Chapter 24).

Another important issue NERA addressed was the method used to reconcile marginal costs to the system revenue requirement. The calculated marginal costs may be greater or less than the allowed revenue requirement, which is normally computed on an accounting or embedded cost basis. Thus, methods such as the equal percent of marginal cost approach are sometimes used for reconciliation, but some analysts prefer to use the **inverse elasticity rule**, where elastic components of usage are priced at the measured marginal cost, while inelastic components of usage are priced higher or lower than marginal cost to absorb the difference between embedded and marginal costs. This issue is discussed further in Chapter 24.

In the NERA method, the functionalization and then classification of system costs as energy-related, demand-related and customer-related is performed, just as in a traditional embedded cost of service study. The marginal cost of each of these elements is then estimated using a wide variety of techniques. These marginal costs are then multiplied by the billing determinants for each class to obtain the marginal cost by class, commonly referred to as the marginal cost revenue requirement. The MCRR is then reconciled to embedded costs and allocated across the classes. Each set of billing determinants used in the calculation is developed on a class

**Table 41. Illustrative example of allocating marginal distribution demand costs by two methods**

| | Residential | Small commercial | Medium commercial | Large commercial and industrial |
|---|---|---|---|---|
| **Class coincident peak-based allocation** | | | | |
| Marginal cost per kW | $100 | $100 | $100 | $98* |
| Probability of circuit peak (MWs) | 5,900 | 1,000 | 3,800 | 1,500 |
| Marginal cost revenue requirement for distribution demand | $590,000,000 | $100,000,000 | $380,000,000 | $147,000,000 |
| Share of costs | 48% | 8% | 31% | 12% |
| **Customer noncoincident peak demand allocation with diversity** | | | | |
| Marginal cost per kW | $100 | $100 | $100 | $98* |
| Noncoincident peak demand (MWs) | 23,878 | 3,131 | 7,482 | 3,561 |
| Effective demand factor | 36% | 37% | 65% | 76% |
| Noncoincident peak demand multiplied by effective demand (MWs, rounded) | 8,600 | 1,150 | 4,850 | 2,700 |
| Marginal cost revenue requirement for distribution demand | $860,000,000 | $115,000,000 | $485,000,000 | $264,600,000 |
| Share of costs | 50% | 7% | 28% | 16% |

*Lower marginal cost of large commercial/industrial reflects lower line losses on primary distribution loads.
Note: Percentages may not add up to 100 because of rounding.

Sources: Southern California Edison. (2017). *Errata to Phase 2 of 2018 General Rate Case: Marginal Cost and Sales Forecast Proposals; 2018 General Rate Case Phase 2 Workpapers*; additional calculations by the authors

basis and, except for the customer-related costs, is divided into time periods and provided for the year as a whole.

For the energy-related costs, the allocation is relatively straightforward, multiplying energy use in each time period by the energy cost in each time period. For the generation capacity costs related to reliability at peak, the allocation typically has not been done using the coincident peak methods most commonly used in embedded cost analysis (and discussed in Section 9.3). Instead, marginal costs are typically allocated over a larger number of hours. This allocation has been done using (1) loss-of-energy expectation, (2) an allocation factor spread equally over the top few hours (100 to 300)[209] or (3) peak capacity allocation factors, effectively a hybrid between the two other methods.[210]

For transmission and distribution costs, the methodology is not as settled, even among marginal cost jurisdictions. Allocation has been either coincident peak-based (related to the probability of peaks on distribution elements) or noncoincident demand-based, with adjustments for diversity between the load at the customer and load at the circuit or substation transformer (which can be developed through statistical analysis). Table 41 illustrates how the two methods can produce

209 This method was developed in California after restructuring in the late 1990s for use in allocating certain transition costs, because generation was expected to be competitive and loss-of-load probability was expected not to exist in a competitive market. San Diego Gas & Electric used the top 100 hours method for allocation of generation costs until 2012 (Saxe, 2012, Chapter 3, pp. 4-5). The company ultimately switched to loss-of-load expectation in 2014 (Barker, 2014). The top 100 hours are still used for allocation of the remaining transition costs of all the major California utilities.

210 Pacific Gas & Electric uses these. Every hour in excess of 80% of the peak is assigned a contribution to peak based on the load minus 80% of the peak. The mathematics mean that the peak hour has an allocation that is 20 times the allocation of an hour that is 81% of the peak and twice the allocation of an hour that is 90% of the peak. In past cases, the company used the gross load curve for both generation and distribution; in 2016, it switched for generation to the load curve net of wind and solar generation while using gross load for distribution. See Pacific Gas & Electric (2016), chapters 9 and 10.

substantially different outcomes (Southern California Edison, 2017a, 2017b, pp. 59-61 and Appendix B, with additional calculations by the authors).[211] Data from Southern California Edison were used because the company currently employs a hybrid of both methods.

Similar to its use of PCAF for generation allocation, Pacific Gas & Electric (PG&E) uses a PCAF method at the local level (each of its 17 divisions) for distribution costs (Pacific Gas & Electric, 2016, Chapter 10). Nevada uses an hourly allocation method based on probability of peak using the system peak demand from which its costs were calculated (Bohrman, 2013, pp. 3-8).

Analysts must be extremely careful when calculating the MCRR, particularly associated with T&D demand. The reason is that not all kWs are the same. Many utilities use one type of kW when developing a marginal cost per kW of demand or capacity (e.g., a kW of substation capacity, where there are 25,000 MWs of such capacity on a utility system) and then multiply the marginal costs by a kW that measures a different type of demand (for example, system peak demand where there are only 15,000 kWs of demand). In particular, when the marginal cost is measured based on a larger number of kWs than the kWs on which the cost is allocated, the result is to assign too few costs as demand-related; this overweights the customer costs in a distribution cost calculation. Additionally, controversy can arrive in measuring the kWs of demand for cost allocation. Although there is no hard and fast rule, two examples in Appendix C illustrate the concerns.

## 18.2 Marginal Costs in an Oversized System

T&D systems have tended to be oversized because equipment (transformers, wires, etc.) comes in fixed sizes. Moreover, oversizing could theoretically be cheaper in the long run than having to return to the same site to change out equipment, particularly when underground lines have been installed. Although it may be economically preferable in some circumstances, this oversizing tends to reduce intermediate-term marginal T&D costs below full long-run marginal costs or embedded costs.

Increased marginal costs for T&D do not necessarily result from high utility rates of return and strong financial incentives for rate base growth, as noted in almost every utility presentation and analyst report, because intermediate-term marginal cost methods usually have not included system replacements, as discussed in Chapter 20 and Appendix D. System replacements and incremental investments to improve safety and reliability (but not to serve new demand) are a large component of new T&D construction by utilities.

Generation is even more complex. Not only was it uneconomic in the past to build generation in small increments, but there were significant benefits of capital substitution (spending money on capital to reduce the use of expensive fuel) that created excess expensive capacity. In the past, when vertically integrated utilities built coal and nuclear plants, they would conduct planning exercises that provided a justification for those projects based on extremely long-term estimates of future fuel costs and future dispatch. As a result, large portions of the investment-related costs of these plants were justified based on savings of costly fuel and purchased power relative to building peaking generation. The forecast relatively high loads and high fuel prices did not always materialize, and long lead times of large projects meant they could not be economically changed or canceled in cases where the forecasts turned out to be wrong. The disconnect between generation construction and short-run marginal costs also resulted in stranded costs when restructuring took place.

A similar phenomenon occurred more recently as investments were made in expensive environmental retrofits of coal plants instead of retiring the units. Some of these investments ended up being uneconomic given lower than expected prices for natural gas and renewables, not to mention the prospect of greenhouse gas regulation.

For a number of utilities, a short-run marginal cost — assuming the existence of these future plants with high capital cost and low-cost fuel — was used to evaluate energy efficiency, renewables and CHP and to design rates. This methodology effectively gives preference to utility resources while depressing the avoided cost paid to independent power producers, finding less energy efficiency to be cost-effective,

211 Loads are rounded off to the nearest 50 MWs in the table, leaving out small classes and granular detail for ease of exposition.

and lowering incentives for customer-side response through rate design. Examples include Duke Power and Carolina Power and Light Co. from 1982 to 1985, which assumed that future coal and nuclear plants would be built when evaluating PURPA projects (Marcus, 1984, pp. 10-23). Another example is the calculations by Ontario Hydro for evaluation of energy efficiency and private power prior to and during the 1990-1993 demand/supply plan hearings at the Environmental Assessment Board (Marcus, 1988, pp. 14-16). A third, from 1990-1991 hearings, is Manitoba Hydro's analysis of energy efficiency using differential revenue requirement analyses assuming that the Conawapa hydro project would be constructed (Goodman and Marcus, 1990, pp. 132-133, F34-F45). Appendix E provides a mathematical discussion of this issue.[212]

Then, when excess capacity appeared, short-run marginal energy costs declined. The need for generation capacity also declined, although the extent to which that decline was recognized in short-run marginal cost methods varied across jurisdictions (see Section 19.3).

## 18.3 Impact of New Technology on Marginal Cost Analysis

Excess capacity can be the result of other cost transitions made for a combination of economic and environmental reasons — in particular, the transition to renewables and other related technologies (storage) that are not fuel-intensive.

### 18.3.1 Renewable Energy

Low-cost wind and solar resources are being installed to provide economic and environmental benefits and reduce fuel use even where capacity is not needed and in some cases are causing the retirements of older plants.[213] In some instances, the total cost of new renewable generation can be less than the fuel and O&M costs of generation that it displaces.

These resources have already been reducing short-term market prices in virtually all ISOs/RTOs. Short-run energy market prices are even sometimes negative in off-peak hours, due to generation that cannot shut down and restart for the next peak period and the renewable energy tax credits that make operating some resources profitable even if they need to pay for the market to absorb their energy output.

The renewable transition makes the traditional marginal cost methodology less relevant. Capacity costs and short-run marginal energy costs are low, while embedded costs remain high. Essentially a short-run marginal cost method sends price signals that energy is cheap because the fossil-fueled component of energy is being used less frequently and is becoming less costly when it is used, while generation capacity costs are also low unless artificially increased.

However, while short-run marginal costs are decreasing, embedded system generation costs are remaining at current levels or increasing because additional capacity is being brought on in advance of need. Other effects on utility generation revenue requirements arise because: (1) some renewables acquired relatively early may be relatively expensive compared with newer renewables in the face of declining cost curves; (2) the growth of renewables may be dampening growth in natural gas prices, which makes renewable energy look less cost-effective than it really is; and (3) in some cases, accelerated recovery of costs reflecting the early retirement of fossil-fueled and nuclear generation may raise embedded costs.

### 18.3.2 Other New Technologies

Smart grid resources can also reduce the marginal cost of distribution capacity by extending the ability to optimize the use of existing capacity. This may increase excess capacity in the short term while reducing long-run costs by substituting controls for wires and fuel. Sections 7.1 and 11.5 discuss in detail the technological characteristics of smart grid functions — including integrated volt/VAR (**volt-ampere reactive**) controls, automated switching and balancing of loads across circuits and enablement of demand response programs — and of storage and demand response resources.

In the near term, large-scale battery storage on the utility grid can be an economic substitute for peaking and relatively

212 Although not strictly a marginal cost issue, divergence between short-run and long-run marginal cost can be one reason for stranded costs (which tend to have been measured against an estimate of short-run cost over time).

213 An explicit example is Xcel Energy's program of substituting "steel for fuel" by replacing coal and gas with wind and solar generation (Xcel Energy, 2018).

inefficient intermediate gas-fired generation — including generation now receiving reliability-must-run (RMR) contracts in transmission rates — while reducing the cost of ramping to meet daily peak loads (Maloney, 2018; see also California Public Utilities Commission, 2018). This could reduce both marginal energy costs and marginal capacity costs if it proves ultimately to be cheaper than a combustion turbine. In the longer term of a decarbonized system with large amounts of intermittent resources, batteries are likely to need to operate for more hours.

> The technology-based economic transition to a smarter grid and a greater role for intermittent and storage resources will change the marginal cost paradigm.

If installed elsewhere on the system, particularly on the distribution system, storage batteries can not only provide support for generation and transmission but remedy distribution overloads or mitigate outages on less reliable radial distribution lines, especially where other smart grid functions are not feasible. The effect would be to reduce marginal capacity costs — although some portion of the cost of the storage should be included as a distribution capacity resource. Behind the meter, storage can provide demand response for the utility as well as significant benefits to customers.

Demand response (e.g., air conditioner cycling, interruptible customers) typically has been used as an emergency capacity resource to avoid bulk generation outages. But it could also be used (when coupled with smart appliances) to mitigate transmission and distribution overloads when the customer is at an appropriate voltage level, reducing future marginal costs.

## 18.4 Summary

The key issues associated with marginal cost analysis on a generic basis are:

- Mixed time horizons. Marginal cost methods often mix short-run, intermediate-term and long-run marginal costs in an inconsistent manner that has tended to have inequitable results over the last 30 years.
- Obsolete technique given changing resource options. Whether short-run or long-run, marginal energy and generation capacity cost allocation methods essentially have been designed for fossil-fueled systems, using economic dispatch. Renewable resources, storage and other resources tend to depress the short-run prices of fossil-fueled energy and existing fossil-fueled capacity.
- Treatment of renewables. With the substitution of renewables (relatively high capital costs but almost zero variable costs) for fossil fuel, short-run marginal energy costs are significantly below the cost of new generation, with significant implications for cost allocation. As an example, a wind plant that runs at 40% to 50% capacity factor (in the Southern Plains) depresses short-run marginal energy cost and may have no impact on capacity costs.
- Availability of storage. Storage is likely to have a lower cost of capacity than fossil-fueled capacity for at least some applications. It also provides more services than conventional peaking capacity depending on where it is sited — for example, it can provide some ancillary services (e.g., fast ramping service) and help with variable renewable energy integration. However, it may have the counterintuitive impact of depressing short-run marginal costs.

In essence, the technology-based economic transition to a smarter grid and a greater role for intermittent and storage resources will ultimately change the marginal cost paradigm from that used for the last four decades while blurring the traditional distinctions among generation, transmission and distribution costs. The short-run marginal cost paradigm based primarily on variable costs of fossil-fueled generation is becoming less central to the fundamental economics of electricity service for which regulation must account. That change has not been fully analyzed within the structure of marginal cost rate-making, but a pathway for such analysis will be discussed in Chapter 25.

# 19. Generation in Marginal Cost of Service Studies

The theory of marginal generation costs starts from the position that electric generation is a joint product, producing energy as well as capacity or reliability. When marginal cost methods were introduced in the 1970s, they constituted a significant advance over the previously used embedded cost theory that assumed that generation capital investment and nondispatch O&M costs are all demand-related and only short-term variable costs are energy-related. The marginal cost paradigm recognizes in some way, albeit imperfectly, that with a variety of generating plant technologies, capital can be substituted for energy and that all capital is not related to the need to serve peak demand.

## 19.1 Long-Run Marginal Cost of Generation

The first key question regarding marginal generation costs is the balance between short-run and long-run marginal costs. There are two options for explicitly calculating long-run marginal costs. Both are based on the cost of building and operating new resources.

The first option is the use of long-run marginal costs (referred to as long-run incremental costs by the entities that developed these methods) to allocate generation costs based on plant types. This method was developed in the Pacific Northwest, where large portions of the systems were energy-constrained. Hydro systems have very flexible capacity but depend on water for energy generation, and the supply of water is both limited under adverse conditions and not controllable. Under this method, the cost of new baseload generation in a resource plan was calculated as the total marginal generation cost. The cost of peaking generation (usually a combustion turbine) was determined to be the peak cost, and the remaining costs were energy-related.[214] In the past, the baseload generation cost was often a coal plant. This method has recently been modified in Oregon to use a combustion turbine for peak generation and a mix of combined cycle gas generation and wind generation for the nonpeak alternative (Paice, 2013, pp. 7-8).

The second long-run marginal cost option has been used by the California Public Utilities Commission for purposes other than cost allocation and rate design. Energy and Environmental Economics Inc. (E3) developed a relatively sophisticated hourly long-run incremental cost model.[215] The California commission has used the E3 model to evaluate energy efficiency, demand response and distributed generation for a number of years, although it has not yet used it for rate design. The generation components of this method have an evaluation period of up to 30 years. The model is designed to assume the short-run avoided cost until the year when capacity is projected to be needed and the full cost of a combined cycle generator if the long-run base total fossil-fueled generation cost is in equilibrium. The effect of this, in the past three decades, would have been to understate generation marginal costs compared with those that would exist under an equilibrium market. However, if the year of capacity need is set to the current year, which has been done in some recent analyses, the model becomes a full long-run marginal cost model, alleviating this problem.

E3 divides the costs into energy and capacity, with the costs of a simple-cycle combustion turbine (net of profits received for energy and ancillary services) treated as capacity-related and all remaining combined cycle costs as energy-related. The E3 model then shapes the energy costs into an

214 This method is similar to the equivalent peaker method (discussed in Section 9.1), except that it includes both capacity and energy.

215 The description of this method is taken from Horii, Price, Cutter, Ming and Chawla, 2016.

hourly load shape using information on load shapes over time (including changes resulting from renewable resource additions) and adds a projection of line losses, carbon dioxide costs and ancillary services to obtain a market price. To obtain the full marginal or avoided energy cost — to the extent that renewable resources (net of their resource-specific capacity credits) cost more than the energy-related cost of a combined cycle unit — the resulting extra costs of meeting the renewable portfolio standard over the 20-year period are added to the market-based costs.

## 19.2 Short-Run Marginal Energy Costs

Short-run marginal energy costs normally are calculated from a production cost or similar model on a time-differentiated (or even hourly) basis. These calculations are made over a relatively short period (typically one to six years out, depending on the utility). Marginal energy costs in the West — whether simulated directly or simulated through a market pricing version of a production cost model — typically have been dependent on the cost of gas and the overall efficiency of the system (i.e., the percentage of time gas was the incremental fuel, the type of gas plants used and the amount of baseload or intermittent generation available). This changes in very wet months, when hydro may be the marginal resource, or increasingly at midday on light-load days, when solar becomes a market driver. In Texas and the Plains states, wind is increasingly a market-driving resource. For utilities in the Midwest, South and East, the incremental fuel is typically a mix of gas-fired generation during peak and midpeak periods with coal-fired generation off-peak in some locations. Some utilities face much higher marginal costs or market prices in extreme winter weather because of gas price spikes, limits on gas availability, high peak loads and unreliability of service due to freezing of coal piles and some mechanical parts of power plants and gas wells.

In California and Nevada, utilities typically have modeled and averaged marginal energy costs over one or three years, corresponding to the length of time between rate cases, but PG&E uses six years. These very short-run energy analyses, particularly when coupled with long-run generation capacity cost analyses, tend to overstate the balance of costs for customer classes with lower load factors and understate them for customer classes with higher load factors. The cost of a combustion turbine, which is allocated heavily based on peak conditions, becomes a larger portion of marginal generation costs if short-run energy costs are lower than if higher longer-run costs are used.

It is of key importance that reasonable natural gas price forecasts are used, particularly if looking out beyond a very short time horizon. In much of the country, the modeling outputs are very sensitive to this input factor, and key results can vary greatly depending on the natural gas forecast. The E3 long-run incremental cost forecast uses short-term forecasts from futures and a longer-term mix of forecasts from the U.S. Energy Information Administration and the California Energy Commission's *Integrated Electric Policy Report* (Horii et al., 2016, pp. 5-8). Utilities tend to use their own forecasts, but in California those forecasts are updated after intervenor testimony is filed.

Greenhouse gas emissions are an important marginal cost, but there is not a consensus method to address it. Carbon cost is, in theory, internalized by California's cap-and-trade system, although it becomes difficult to properly model the dispatch in the Western United States when only California resources and California imports carry carbon values. The **Regional Greenhouse Gas Initiative** market performs a similar function in the Northeastern United States. In all jurisdictions where carbon prices are included, carbon prices must be forecast if longer-term marginal cost methods are used. Prices need to be forecast over the full study duration where markets do not exist for these products. Even in California and the Regional Greenhouse Gas Initiative states, market-determined allowance prices extend out for only a three-year period. However, in places where carbon is not explicitly valued, a marginal cost method should include current or future carbon values associated with fossil-fueled generation to provide forward-looking price signals. In jurisdictions covered by electric sector cap-and-trade programs, there are still questions about whether the marginal cost from the program is sufficient or whether another measure, such as the social cost of carbon or marginal cost of long-term greenhouse gas reductions, is more accurate.

The addition of renewable resources to utility portfolios, especially if added in advance of the need for capacity, depresses marginal energy costs by adding energy with zero fuel costs (or even negative costs in the case of wind energy with the production tax credit). The result is to reduce marginal costs in two ways. It reduces the heat rates of gas-fired generators on the margin. It also decreases the number of hours when a gas-fired resource is on the margin in some places where cheaper coal or surplus hydro (the Pacific Northwest or Canada) can be a marginal source of energy or when renewables are curtailed. In other words, the short-run model reduces energy costs relative to capacity costs when new renewable resources are constructed.

It can be argued that costs of compliance with an RPS are short-run marginal costs, in the sense that if load changes on a permanent basis, a portion of that load must be met with renewable resources. The capital and operating costs of those resources (possibly net of the fixed costs of an equivalent amount of peaking capacity) would replace the market prices and fuel costs from existing generation used to calculate marginal costs.[216] The Nevada utilities first developed calculations using the RPS as an adder to conventional resources in Sierra Pacific Power Co.'s 2010 rate case (Pollard, 2010).[217] The RPS adder was then adopted by California consumer groups (Marcus, 2010b, p. 45) and by Southern California Edison (2014, pp. 31-32). It is also included in the E3 long-run marginal cost model (Horii et al., pp. 36-38). Note that, mathematically, in the Western states that use marginal cost analysis, the RPS adder increases if short-run market energy prices decline (e.g., due to an update that reduces gas prices).

Before deregulation, there was a debate over whether short-run marginal energy costs should be the instantaneous cost in the given hour as envisioned in the original NERA method or should reflect other factors such as unit commitment. Often the actual unit that varies with short-term variation in loads is a flexible resource, not necessarily the least-cost resource, and the dispatch of hydro can change with changes in load. In California, the utilities commission adopted a method that computed marginal costs as the change in total costs for a large utility between a symmetrical increment of several hundred MWs above and several hundred MWs below current loads in each hour. This resulted in a more expansive definition of short-run marginal costs that included not just the incremental costs of a plant running in a given hour but the differences in how many power plants were committed if the load were different — thus causing changes in costs of startups and plants running at minimum load to be available the next day. These unit commitment costs generally increase the marginal costs experienced during peak hours above hourly marginal costs. In current wholesale markets, unit commitment costs tend to be reflected in day-ahead prices because bidders who need to commit a resource must include that cost in their bids.

Several ancillary services defined by FERC and ISOs/RTOs are purchased on an hourly basis. These include spinning reserves, nonspinning reserves available in a time frame of about 10 minutes, in some cases replacement reserves (plants that could fill another reserve type on a contingency basis if that reserve was used in real time) and frequency regulation (both upward and downward) on a minute-to-minute basis. Additionally, there are services that are not officially called ancillary services but that are related. These include the need to assure that enough generation is committed to meet energy requirements (residual unit commitment, acquired daily) and energy that can be dispatched to ramp upward or downward within a bid period to meet changes in demand and changes in variable (typically renewable) resource output that can be forecast hourly or subhourly (e.g., solar). Finally, there are out-of-market real-time costs necessary to maintain system reliability if generation is not available or if transmission contingencies occur. These costs are "uplift" (charged to system loads) by ISOs/RTOs. That said, uplift costs can be

216 As an analogy, in most jurisdictions with retail choice, RPS requirements typically are implemented in a way that is a short-run cost. As a percentage requirement based on load served or retail kWh sales, it automatically varies based on kWhs in a predictable way. Therefore, treating RPS requirements similarly in jurisdictions where generation is regulated is appropriate.

217 Those calculations established the principle, even though they were flawed because they included energy efficiency resources that were cheaper than market prices that could meet Nevada RPS requirements and because the energy efficiency costs did not consider a time value of money (Marcus, 2010c, pp. 7-8).

incurred unnecessarily if ISOs/RTOs fail to optimize existing markets to provide necessary reserves and other ancillary services to provide necessary grid support.

Although some utilities and industrial customers suggest these costs are really capacity costs and thus should be subsumed in the marginal cost of capacity, they are paid for in each hour along with market energy costs, so that, regardless of the semantics, they should be allocated on an hourly basis. The costs are not large in normally functioning markets. For purposes of evaluation of energy efficiency in California, E3 uses a figure of 0.7% of marginal energy costs for ancillary services (Horii et al., pp. 25-26),[218] a decrease from 1% several years ago. A more detailed study of California ISO ancillary services costs for the 12 months ending April 2010 ended up with 0.8% of marginal energy cost, with amounts ranging from 1.17% summer on-peak to 0.61% winter midpeak (Marcus, 2010b, p. 45). Although not large, the costs are real and should be included in a short-run energy costing methodology.

Costs paid on an hourly basis for intrahour ramping may also be incurred. This is particularly an issue in the Western U.S. The drop-off of solar energy as the sun sets plus increasing of loads toward an evening peak can cause a doubling of loads served by other resources (i.e., net loads, excluding wind and solar generation) on some low-load days in the spring and fall. This causes the need to rapidly ramp up conventional generation, such as natural gas and hydro, and opens up an important new role for storage. Any energy costs of ramp should be assigned as a marginal cost to those hours.

## 19.3 Short-Run Marginal Generation Capacity Costs

Under the short-run marginal cost method, the theory, as originally developed in the late 1970s, is that the value of generation capacity is capped at the least cost of acquiring generation for reliability. If all that was needed was capacity, a cheap resource to provide capacity (such as a peaking plant) could be built. Any more expensive generation would have been built specifically to reduce total system costs (fuel plus capacity). Under this method, the cost of the peaker is multiplied by the real economic carrying charge, and O&M and A&G costs are added to it.

A number of technologies could be the least-cost generating capacity option, including:

- Conventional peaking generation, demand response or economic curtailment.
- Midrange generation net of fuel or market price savings.
- Short-term or intermediate-term power purchases.
- Results of RTO capacity market auctions or market prices for capacity procured for resource adequacy (if applicable).
- Centralized or distributed storage net of fuel or market price savings.

In equilibrium, without cheaper short-term options, the cost of a peaker would theoretically equal the shortage value customers experience from generation outages. That is the reason marginal generation costs have typically used a peaker, because they effectively assume equilibrium exists. The California and Nevada utilities other than PG&E use the full cost of a combustion turbine as the basis for marginal capacity costs. PG&E, the California Public Utilities Commission advocacy staff and other consumer intervenors recognize that the short-run marginal cost can be less than a peaker. Lower costs should occur if capacity is either unneeded or so economic that energy savings from construction of baseload generation exceeds the cost of the plant, or if cheaper options than a combustion turbine peaker are available. Theoretically, the marginal generation capacity cost can also be higher for short periods when there are shortages of capacity within the lead time of building generation, but those conditions have not occurred since the early 1980s (California Public Utilities Commission, 1983, pp. 220-222).

In 2017-2018, Southern California Edison claimed that some of the need for system reliability was not caused by peak loads but instead by the requirement to have adequate capacity available to ramp generation from midafternoon to the evening peak in periods of the year with relatively low loads (and relatively high output from conventional hydro plants that reduced their flexibility for use in peaking). Although many options are available to reduce the size and scope of the ramp, particularly storage and use of flexible

218 These costs do not include ramp, residual unit commitment or out-of-market costs.

loads in areas such as water supply and delivery (see Marcus, 2010b, and Lazar, 2016), one of the options the California ISO identified was gas-fired generation. New storage options may be especially well suited for dealing with problems of ramping because of the timing of both charging and discharging batteries or taking other actions like storing hot or chilled water.

Equating a marginal capacity cost based on a peaker with very short-run energy costs creates a mismatch that is detrimental to customers with peakier load shapes. Several points must be considered here.

1. Costs of peakers vary. Smaller combustion turbines and aero-derivative turbines are more expensive than larger combustion turbines. Some of these smaller turbines have costs that approach or even exceed the cost of a larger combined cycle plant.[219] When conducting marginal cost studies, some utilities and industrial customers have requested approval for expensive peakers as marginal capacity costs.[220] However, that point ignores the key finding of the NERA method: that the marginal cost of capacity is the least costly source of capacity, so that by definition the more expensive peaker installed for other reasons is not the marginal cost of capacity under that framework.
2. Financing costs for peakers vary. In California, a number of parties (including E3) have used merchant plant financing, which is more expensive than utility financing, to develop the marginal cost of capacity. Again, the issue is that a merchant plant is not the least costly source of capacity because merchant plants have higher required returns. Furthermore, merchant plants often have off-take contracts that are shorter than the physical life of the plant. Using the shorter contract life for capital recovery also inappropriately increases the marginal cost of generating capacity.
3. Even a peaking power plant would make money in the market (or save fuel and purchased power costs in a vertically integrated utility that is not closely affiliated with a market). Combustion turbines installed in the 1970s, when the NERA method was developed, had heat rates in the range of 15,000 Btu per kWh and burned expensive diesel oil. They were machines that provided essentially pure capacity — reserves that were turned on to keep the lights from going out. Much of the gas-fired load at that time came from less flexible steam plants with heat rates from 9,000 to 12,000 Btu per kWh. Modern peakers have a heat rate in the range of 10,000 Btu per kWh (or lower) and burn gas. They actually have better heat rates than many of the older intermediate steam plants, as well as greater flexibility. As a result, when modern peakers are used, they generally earn at least some money in the market or save fuel and purchased power costs.[221] They also can earn revenue from selling dispatch rights in the 10-minute (nonspinning) reserve ancillary service market. This revenue should be netted against the cost of the combustion turbine, because it pays a portion of the cost of capacity.
4. Peaking generation may not be the least-cost capacity resource. It is possible for an intermediate resource such as a combined cycle generator to have a lower net cost than a combustion turbine. In particular, the capital and long-term O&M cost of the combined cycle generator minus the revenue that it would earn in the market or the fuel it would save can be less than the cost of a combustion turbine. Even with excess capacity, this outcome can sometimes occur, particularly if a relatively expensive turbine is erroneously considered as the peaking unit (as discussed earlier in this list).
5. Storage costs may be cheaper than combustion turbines. Under current conditions, it is possible that storage costs net of energy savings relative to market prices can be cheaper than conventional peaking generation. In particular, PG&E is installing and contracting for about 550 MWs of batteries with four-hour storage to meet system needs and replace 570 MWs of RMR peaking and

219 A utility might have installed some of these smaller turbines for reasons such as alleviating transmission constraints, meeting time constraints (if the smaller turbines had less stringent siting requirements) or responding to specialized system needs such as black start capability.

220 See, for example, Phillips (2018, pp. 5-11), where the testimony argues for the usage of a 50-MW turbine costing $1,600 per kW instead of a cheaper 100-MW turbine.

221 See Section 1.1 for more discussion and quantitative examples of this phenomenon.

combined cycle generation (Maloney, 2018; California Public Utilities Commission, 2018). RMR generation receives payments on a cost of service basis including capital and operating costs, although the specific plants being replaced are partly depreciated.

6. Additionally, pure capacity can be available at considerably lower costs than a combustion turbine. Systemwide actual and projected prices in the California resource adequacy markets are $30 to $40 per kW-year over the period of 2017-2021 (Chow and Brant, 2018, p. 21) with even the peak monthly prices from July to September rising no higher than $4.50 per kW-month (Chow and Brant, p. 32). Capacity market prices are generally similar in the PJM region, with higher prices in transmission-constrained pockets of New Jersey and occasionally other areas; new demand resources, renewables and gas-fired combined cycle generation have been added at those low prices (PJM, n.d.).[222] Resource adequacy capacity does not come with the physical hedge against high market prices provided by the combustion turbine's known heat rate, but it is much less costly. It is arguably the newest version of "pure capacity" as NERA originally defined it. PG&E estimates the capacity cost during a period of surplus as the long-term O&M cost of a combined cycle generating plant, because a combined cycle plant that could not earn its long-term O&M would go out of service, reducing any available surplus (Pacific Gas & Electric, 2016, Chapter 2).

In sum, the combustion turbine peaker that is the typical choice for marginal capacity costs under the NERA method, as well as under long-run incremental costs, is likely to significantly overstate capacity costs given the economics of new large-scale storage facilities and significant capacity surpluses.

To the extent there is a marginal capacity cost for ramping capability, it can best be understood as an hourly capacity cost that is negative in the hour or two before the ramp begins, a positive hourly cost in the steepest several hours of the ramp and lower but still positive hourly cost as the ramp becomes flatter, continuing through and just beyond the evening peak.

But, for allocation purposes, the cost needs to be first divided between ramp caused by customer loads and ramp caused by generation characteristics, which should be feasible. This is another example of how the emerging wind- and solar-dominated grid challenges traditional methods of cost allocation. To the extent that the need for capacity for ramping, and hence part of its cost, is caused by generation characteristics, it should not be a load-related marginal cost for allocation to the classes that contribute to the ramp.[223] The generation-related ramp effectively becomes part of the cost of the generation resources causing the ramp under a short-run marginal cost theory, such as the one NERA defined. To the extent that generation-related ramping costs are recovered as incurred periodically in energy costs or ancillary service or other charges from the RTO, they should be part of marginal energy costs. Although these concepts are relatively clear, their implementation is not clear at all, with disagreements among parties on both the generation-related portion of ramp costs, the definition of ramp hours (for example, whether more than one large ramp should be counted on a single day) and the method of allocating costs to both hours and classes. Storage units are more effective for ramping than thermal peakers because they can both charge in the preramp hours and discharge to clip the peak, reducing the total amount of ramp more than a thermal plant, whether the storage is installed as a bulk power resource or for other purposes.

222 Similar capacity prices have prevailed in New York, outside the New York City load pocket (New York Independent System Operator, n.d.). Capacity prices in MISO are even lower due to a continuing surplus and renewable additions, while prices in New England were higher for a few years after 2016 and have recently fallen to the California range.

223 Although the generation-related cost should not be part of the class allocation, it may be appropriate to include some of that cost in rate design to provide a greater discouragement to ramping loads.

# 20. Transmission and Shared Distribution in Marginal Cost of Service Studies

## 20.1 Marginal Transmission Costs

Marginal transmission costs have not received the attention that marginal generation and distribution costs have received, because in large parts of the country transmission is partly if not wholly under FERC jurisdiction. Thus, California utilities only calculate marginal transmission costs as an input to the process of calculating the contribution to margin of economic development rates, rather than for cost allocation and rate design. Nevada calculates marginal transmission costs using the NERA method. But since there is no joint product (such as generation energy and capacity, or distribution lines and customer connections) and Nevada allocates costs by functions (see Chapter 24), there is little controversy. Southern California Edison breaks its transmission costs into transmission (115 kV and above) and subtransmission (69 kV and below) because specific factors relating to the physical layout of its system left its subtransmission system under Public Utilities Commission regulation, where it is treated as part of the company's distribution marginal costs.[224]

The NERA method for marginal transmission costs involves some analysis of the relationship between transmission system design and peak loads. Although the original method involves regression analysis between cumulative investment in load-related transmission (calculated in real, inflation-adjusted dollars) and cumulative increases to peak load, two other methods have been developed. The first, the total investment method, examines total investment divided by the change in peak load. The second, the discounted total investment method, uses discounted total investment divided by the discounted change in peak load. This assigns lower weights to investments occurring later in a projected analysis period relative to investments occurring earlier. The specific choice among these three methods can create relatively small differences (unless miscalculated). The investment cost is annualized by multiplying by the RECC. Investment costs are defined narrowly. As an example typical of most utilities, Southern California Edison stated in its most recent rate design case:

> Projects discretely identified as load growth are only considered in the analysis. All projects not related to load growth (i.e., grid reliability, infrastructure replacement projects, grid modernization, automation, etc.) are excluded from this analysis (2017b, p. 37).

The NERA method can be applied to the transmission system as a whole or to transmission and subtransmission voltage levels and to lines and substations separately.

O&M costs are added to the annualized capital costs. There are two conceptual methods for doing this. The original NERA method averages O&M costs (in real terms) divided by kWs of load (i.e., calculated in dollars per kW) over a period containing both historical and forecast years. An alternative method used by PG&E calculates O&M costs as a percentage of plant and adds it only to the new plant. Using this method, O&M costs are lower because the assumption is made that O&M is tied to new plant rather than maintaining the system in order to retain all loads.

The NERA method essentially ignores large parts of the transmission system and therefore generally ends up with marginal transmission costs well below embedded costs. It also fails to recognize that peaking resources and storage are

224 California utilities calculate a marginal cost of transmission as an element of cost when determining how much contribution to margin is provided by loads such as economic development rates, but it is not used for allocation of costs to customer classes (which is done by FERC) and is therefore not reviewed carefully in rate cases.

often strategically located near loads where transmission is constrained to reduce the need for transmission. For example, the city of Burbank, California, incurred additional costs to locate the Lake generating unit in the heart of the urban area; an offsetting benefit was avoidance of transmission costs.

First, interties to connect utilities, or to connect remote generation plants for purposes of obtaining cheaper sources of generation and increasing imports of generation capacity, are often simply ignored. They are treated as "inframarginal" sources of generation (built because they were theoretically cost-effective relative to the existing system without those lines). As a result, the cost of interties ends up neither in the marginal generation costs (where the only effect is to depress short-run marginal energy costs) nor in the marginal transmission costs (because the NERA method assumes them to be a source of cheap generation). Nor do the net revenues the utility receives for off-system energy sales (to the extent that the concept still exists in competitive wholesale markets) end up as an offset to transmission costs, even though such sales could be one reason for constructing intertie capacity.

The second set of costs that methods like the NERA method ignore is the cost of system replacement. The argument is that once the utility commits to build one system of transmission, the RECC method has the effect of deferring all replacements. The end result is that, as pieces of the system that were built 30 to 60 years ago are replaced, they are part of the embedded costs but not part of the marginal costs. System replacements can be a significant portion of the cost of new rate base. This issue is discussed further in the next section.

Third, any transmission and distribution costs related to improving reliability on the existing system (instead of specifically adding new capacity) or automating the system (to improve reliability or reduce capacity needs) are excluded under the pure version of this method. This exclusion is at variance to the theory of marginal generation costs, where in equilibrium the value of avoided shortages equals the value of the least-cost resource able to meet the need. Here, avoided shortages are assigned no value.

Fourth, the transmission and subtransmission systems are heavily networked and are built to avoid outages under various load conditions throughout the year with one or two elements of the system out of service. This networking essentially means that even though the NERA method relates investment to peak, the cost causation of that relationship is unclear, and a significant portion of costs may be related to lower-load hours than the peak. The hourly allocation methods discussed in Section 25.2 may provide guidance in treating some transmission costs in marginal cost studies, by assigning these costs to all hours in which the assets are deployed.

## 20.2 Marginal Shared Distribution Costs

The most controversial issue for the calculation of marginal distribution costs is the same issue raised in the embedded cost section. Is a portion of the shared distribution system, particularly the poles, conductors and transformers in FERC accounts 364 through 368, customer-related? The authors of this manual believe strongly that these costs are not customer-related; Section 11.2 on embedded costs addresses this question in detail. This section will comment only on some specific issues of the customer/demand classification as they apply specifically to marginal costs for the shared elements of the distribution system.

The NERA method for marginal distribution capacity costs unrelated to customer connections is similar to that for marginal transmission costs, involving an analysis of the relationship between distribution system design and peak loads. Again, the three methods used are regression analysis, the total investment method and discounted total investment method, all discussed in Section 20.1. The investment cost is annualized by multiplying by the RECC.

The marginal cost of distribution capacity can be developed for the distribution system as a whole, as well as separately for lines and substations. A number of utilities (including Southern California Edison, San Diego Gas & Electric and the Nevada utilities) have separate calculations for distribution substations and lines. PG&E uses regional costs. It calculates costs individually for more than 200 distribution planning areas for purposes of economic development rates and aggregates them up to 17 utility divisions for purposes of marginal cost calculation for cost allocation and rate design (Pacific Gas & Electric, 2016, chapters 5 and 6). Using all of the distribution planning areas (as was proposed in the 1990s) is so granular that it would be difficult to examine and audit the relationship of costs to cost drivers. This is true in part because costs are dependent on the amount of excess capacity in local areas. In addition, customers who are large relative to the distribution system may never pay for capacity needed to serve them in some cases. And customers in slow-growing areas are charged less than those where load is growing faster, even if those customers are using a significant portion of the distribution system.

O&M costs are added to the annualized capital costs. As with transmission, there are two conceptual methods for doing this. The original NERA method averages O&M costs (in real terms) divided by kWs of load over a period containing both historical and forecast years. The alternative would calculate O&M costs as a percentage of plant and include it as an adder only to new plant.[225]

Southern California Edison and San Diego Gas & Electric aggregate all primary distribution circuit costs, including those that are part of line extensions, and treat them as demand costs. PG&E treats all primary distribution costs associated with line extensions as demand costs, again calculated regionally, but uses a different, less diverse measure of demand — demand at the final line transformer, rather than demand at the substation, to allocate these costs (Pacific Gas & Electric, 2016, Chapter 6).

The Nevada utilities make a distinction between costs covered by the line extension allowance (which they call facilities costs) and other distribution substation and circuit costs. Facilities costs are allocated to customer classes based on the cost of facilities built for each class that are recovered from customers because they are less than the line extension allowance. Costs are higher in dollars per customer in nonresidential classes than in the residential class. These costs are annualized by the RECC and have O&M added to them (Walsh, 2013, p. 9). This treatment is identical to the **rental method** for customer connection costs discussed in Section 21.1. Thus, as the line extension allowance is increased, more costs are allocated to residential customers because land developers pay fewer of them. Unlike most utilities, the Nevada utilities have separate rates for single-family and multifamily customers. The result of this split of the residential class is that multifamily customers, with less expensive hookups on a dollars-per-customer basis, do not subsidize single-family customers, in contrast to the case across most of North America when distribution circuit costs are partly assigned on a per-customer basis. We discuss the class definition issue in Section 5.2.

Central Maine Power, which uses marginal costs to allocate distribution costs, also divides the distribution system between line extension and other distribution facilities and uses a different allocation among classes for line extension costs that allocates the costs more heavily to residential customers (Strunk, 2018, pp. 14-18).

Pacific Power's Oregon rate cases have a "commitment-related" component to primary distribution costs that is similar to the minimum system methods used by utilities conducting embedded cost studies and has similar issues (Paice, 2013, pp. 6, 9-11). Although the Oregon utility commission has accepted this for interclass cost allocation purposes, it does not include these as customer-related in the rate design phase of rate-making (B. Jenks, Oregon Citizens' Utility Board, personal communication, June 4, 2019).

The NERA method again ignores replacement costs, which constitute the majority of new distribution plant for many utilities' systems, in addition to ignoring costs of improving reliability. A good argument can be made that replacement costs are truly marginal costs and that the utility needs to make replacements to serve its existing load safely and reliably. First, regardless of the workings of the RECC method, assuming that replacement costs are automatically committed when a new piece of distribution equipment is built is a monopoly-based argument and does not work in a truly competitive market. The marginal cost relates to both incremental and decremental demand. A replacement is needed to assure that demand does not decline but is instead

225 This is PG&E's method because the company claims that O&M costs are not marginal once the plant is installed (Pacific Gas & Electric, 2016, Chapter 5, p. 11).

served reliably. The fact that replacements are a marginal cost can be analogized to other industries, such as trucking. A more detailed theoretical exposition is given in Appendix D.

Adding in replacement costs (calculated in dollars per kW like O&M costs, but with an adder for the present value of revenue requirements) has been estimated in the past to increase marginal costs for Southern California Edison by 40% for distribution and 31% for subtransmission (Jones and Marcus, 2015, p. 30) and for PG&E by 46% for primary distribution and 27% for new business (Marcus, 2010b, pp. 36-37). Replacement costs were included as marginal costs in the 1996 PG&E gas cost adjustment proceeding (California Public Utilities Commission, 1995) but have not been included in any electric marginal costs because all California cases have been settled for almost 25 years.

Some distribution costs that are similar to replacement costs are actually policy-related and may not be marginal costs as a result (e.g., urban undergrounding of overhead lines; other changes related to safety and environmental protection). As with embedded costs and for the same reasons, costs in FERC accounts 364 through 367 should be considered as common system costs rather than as costs assigned to individual customers. Even though they are included in Account 368, as with embedded costs, capacitors and regulators need to at least be functionalized as primary distribution costs when calculating marginal costs, unless the dual function of the capacitor as a generation resource is recognized,[226] just as with embedded costs. They reduce losses and increase distribution capacity by supporting voltage and reducing amounts of reactive power.

Many smart grid investments such as automated switching and integrated volt/VAR controls (as well as potential investments in storage and targeted demand response programs) increase overcapacity and reduce distribution marginal costs calculated using the NERA method by reducing the need to build new lines. Under this method, this overcapacity will cause customer costs to be emphasized relative to other distribution costs.

Distribution marginal costs end up with tricky calculation issues because of differences in the determinants on which marginal cost calculations are made and the costing determinants on which revenue allocation is conducted. Not all kWs are equal. This issue is referenced here as a concern regarding marginal distribution costs but is addressed in more detail in Chapter 24 on reconciling marginal costs to embedded costs.

The transformer is an intermediate piece of equipment. In the larger C&I classes, a transformer will often serve a single secondary voltage customer, while for residential customers it may serve a single rural customer, a group of six to 10 suburban customers or 50 apartments or more. In the small and medium commercial classes, several customers are served by a single transformer in some cases, while some customers (particularly larger or three-phase customers) are served with single transformers. There are also differences in cost between single-phase and three-phase transformers. Single-phase equipment is adequate for serving nearly all residential customers and many small commercial customers.

Some utilities have allocated these costs to classes as marginal costs based on the average cost of a transformer serving the class. If this treatment is used for class allocation, transformer costs should not be fixed customer costs for purposes of rate design because of the wide variety of customer sizes and transformer configurations. In older urban areas, secondary line is often networked across several transformers, with some service drops connected directly to the transformer and some connected to the networked secondary line. In these cases, the use of secondary lines to connect the transformer to the customer is more of a common cost than a connection cost, unlike in more modern design configurations, where secondary distribution might be an economic alternative for customer connection.

If a transformer cost is considered part of the customer connection function, a portion of transformer costs is likely not marginal costs, and only the cost of the smallest transformer should be included. Transformers typically are purchased using an algorithm to minimize the present value of capital costs and load-related and nonload-related (core) losses. The extra costs of the transformers above the

226 If a capacitor is deemed to have a generation function, it is not a marginal cost at all under the NERA method.

minimum costs would be inframarginal costs of providing energy and capacity rather than customer connection costs. However, these extra costs have been difficult to measure in past cases. Also, many utilities claim that the new energy standards for line transformers mean they no longer need to optimize transformer costs against losses and they only need to meet but not exceed the federal standard. Capacitors and voltage regulators are also not part of transformer costs for either customer connection or secondary distribution demand but instead should be quantified together with other primary distribution costs.

# 21. Customer Connection and Service in Marginal Cost of Service Studies

The customer connection costs, also known as point of delivery costs, include the service drop and meter and may include the final line transformer and any secondary distribution lines that are not networked with other transformers.[227] Primary lines are typically not point of delivery costs, although several utilities include either line extension costs or some type of minimum system as customer costs. The basic customer method primarily includes the service and meter, although some states include a transformer. As a matter of calculation, it is necessary to determine a meter cost for each customer class. Additionally, customers cause the utility to incur costs of billing, collections and similar items.

## 21.1 Traditional Computation Methods

There are two longstanding methods for computing marginal customer connection costs. The first is the rental method, where the cost of new customer connection equipment is multiplied by the RECC to obtain a value at which a customer could be presumed to rent the equipment from the utility. O&M costs are added to these annualized capital costs. This method is a direct continuation of the NERA method.

The second method is the new-customer-only (NCO) method. It calculates a marginal cost based on the number of new hookups (and possibly replacements) of customer connection equipment in the same time frame as used to measure other marginal costs for generation and transmission. This cost is adjusted by a present value of revenue requirements multiplier to reflect the costs of income taxes and property taxes under utility ownership. Elements of the method were introduced by consumer advocates who recognized that the incremental and decremental costs of hooking up new customers were different (unlike most marginal cost elements) in the mid- to late 1980s. The specific NCO method was first presented by PG&E (in 1993; it has since disavowed the NCO method) and was adopted by consumer advocates with modifications after that time. Again, O&M costs are added.

The rental method has the longest time horizon of all the marginal cost methods in the entire panoply of marginal costs developed by NERA and used by regulators. All customers are assumed to rent equipment based on today's costs and configurations of customer connection equipment, which is largely underground in most newly constructed urban and suburban distribution systems. The method as utilities now implement it generally does not consider the standing stock of equipment. As a result, the rental method assumes that customers with overhead service in urban areas are charged in marginal costs as if they had underground service. So these customers not only have to look at wires and poles, but they face a revenue allocation that assumes they have the amenities of modern suburbs. By failing to use the standing stock, the rental method also assumes that the percentage of new housing stock built as apartments is the same as the percentage of existing housing units that are apartments.[228]

Besides these computational issues, there are significant theoretical issues that caused the development of the NCO

227 A secondary distribution line that is not networked is installed to reduce costs (including line losses) relative to running all services directly off a single transformer. It is thus an economic substitute for longer service lines.

228 The exception to this concern is Nevada, where separate marginal customer costs are calculated for single-family and multifamily homes based on new costs but are applied to the existing stock of each type of housing. This practice has been in place since at least 1999 when the utilities presented the division of the residential class in Public Utilities Commission of Nevada dockets 99-04001 and 99-04005. San Diego Gas & Electric calculates customer connection costs based on the noncoincident demand of the customers and uses demand estimates of existing customers, which also ameliorates this problem to some degree (Saxe, 2016, pp. 6-10).

method. Aside from computational inaccuracies from not using the standing stock, the rental method is not the outcome of a true competitive market. The NCO method reflects as marginal only those costs that are avoidable — incurred at the time when the choice to spend or not spend money on new hookups is made — when the customer chooses to connect to the utility system or when a hookup is replaced. It is thus a shorter-run marginal cost method than the rental method, making the NCO method more consistent with the other short- and intermediate-term means of calculating costs included in the rest of the NERA method. The cost analyst must carefully examine the consistency between the NCO method, which considers the full costs of system replacement, and the methods used for G&T. If replacement costs are used for one category, they should be used for all categories, moving the study toward a total service long-run incremental cost study (see Section 25.1).

The NCO method also comports better with competitive markets and consumer behavior. Consumers typically have the choice to either own or rent any equipment affixed to their homes that costs several hundred to a few thousand dollars. In many cases, consumers nearly always own the equipment, as in the case of curtains or chandeliers. In other cases, there is consumer choice as to ownership or rental, as with propane tanks, solar energy systems,[229] internet routers and (in some parts of North America) water heaters. Even where the rental option is present, the consumer can choose to purchase the equipment. In contrast, the rental method does not simulate the outcome of a competitive market. It is equivalent to assuming there are enough landlords that there is a competitive rental market, who own all the property in a given community. Anyone who wants to live in that community has to rent from one of these owners; no one is allowed to buy property. Rather, this is a market with barriers to entry that prevent true competition. Thus, the analogy of the current rental method to the housing market places an anti-competitive constraint on consumers that would limit their economic choices while protecting the profits of the landlord — or the utility, in this case — from the vagaries of competition.

There is one additional computational issue in the NCO method, where the replacement rate may or may not be considered. In California, the utility commission advocacy office has omitted replacements from the NCO method as well as from calculations of marginal distribution costs. The Utility Reform Network tends to include them for both, yielding higher costs for both demand distribution and customer-related costs. If a replacement cost is needed for the NCO method, utilities often use the highest possible number — the inverse of the depreciable life of the equipment. Although data for service drops may be limited, utilities often have actual rates of replacement of meters and transformers, as well as information that could allow the replacement rates for service drops to be inferred from capital budgeting documents.[230]

## 21.2 Smart Meter Issues

For utilities installing smart meters, a joint product issue arises. A smart meter with the associated data collection network hardware and software serves multiple functions. It provides customer connection and billing while reducing the labor costs of meter reading and other functions. It can also provide a number of other peak load, energy and reliability functions, including enabling TOU pricing and measuring demand response; load research; distribution smart grid functions such as outage detection and (if tied to utility GPS and mapping functions) identification of potential transformer overloads; and even, in some cases, internet access for utility customers.

The NERA method provides a theoretical underpinning that customer connections (analogous to generation capacity) should be provided by the least-cost method. In evaluating past smart meter cases, about 70% of the cost of the AMI system was covered by meter reading benefits; the remainder of the cost was justified by other benefits. Therefore, California

229 Solar systems may be a special case. Renting the equipment generates some tax benefits that can be passed to the consumer in lower rent, while ownership would not have the same tax advantages. This will change if the solar investment tax credit is allowed to expire after 2020 as would occur under current law.

230 There is an accounting issue for meter replacement, because the cost of the meter is capitalized but the cost of meter replacement O&M is often expensed (see Section 21.3). It is important not to count the same cost twice.

ratepayer advocates typically have argued that only 70% of the cost was a customer connection and billing cost and the remainder was not a marginal customer cost. Alternatively, in other studies, more than 100% of the smart meter and data collection installation cost is justified by other savings in power supply and line losses, rendering the metering and meter reading function as a cost-free byproduct.

The division of the smart meter into connection and billing and other benefits can be analyzed in a different way — by netting out all benefits from the smart meter aside from those associated with meter reading and customer accounts, leaving the remainder as connection-related. This is analogous to calculating a marginal capacity cost based on a combined cycle power plant net of savings of fuel and purchased power if it is cheaper than a combustion turbine.

## 21.3 Operations and Maintenance Expenses for Customer Connection

Most utilities that use marginal costs assign the costs of FERC accounts 586 and 597 (meter operations and maintenance) and possibly portions of accounts 583, 584, 593 and 594 (operations and maintenance of underground and overhead lines) related to services and transformers as customer-related. If a transformer is customer connection equipment, Account 595 (transformer maintenance) is also customer-related. Utilities also assign portions of overhead accounts 580 (supervision and engineering), 588 (miscellaneous operating expenses), 590 (maintenance supervision) and 598 (miscellaneous maintenance expenses) to the customer costs. The treatment of these expenses is often an issue, as the specific costs in many of these areas may be more related to shared distribution system costs than to customer connections. These costs typically are developed using an average of several years of historical data and several years of future data.

There are several computational issues.

First, at least some utilities include the labor cost of replacing a meter in Account 586 (Jones and Marcus, 2016, citing San Diego Gas & Electric testimony). Effectively, the cost of replacing meters for customers needing replacement is included in both the O&M costs and the capital costs (because the lessor has the responsibility of replacement in the rental method and the replacement is included in the NCO method). Therefore, replacement meter costs should be removed from Account 586 in the rental method because they would otherwise be double-counted as part of the rental cost. In the NCO method with replacement, the costs of meter installation should be removed from the capital costs for replaced units and left in Account 586 to reflect recurring replacements.

Second, there are issues relating to the real costs of operating and maintaining service drops, some of which also must be dealt with in embedded cost analysis. Utilities may assign costs to service drops based on investment or line miles. But as a practical matter, utilities spend very little on service drops as compared with primary distribution lines. In particular, many utilities have vegetation management standards almost entirely tied to primary lines. They rarely trim trees around secondary wires, except incidentally when primary line trimming is needed, and even more rarely trim trees around service drops, except under emergency conditions. Aside from tree trimming, patrols and inspections are driven by primary lines, not service drops. Therefore, it is necessary to conduct utility-specific analysis on service drop maintenance.

A third issue is that some of the costs in Account 588 are not marginal costs at all. For example, PG&E in a previous case included costs of obtaining additional revenue from nontraditional sources and costs of performing work reimbursed by others. Other costs do not apply to customer connection equipment (environmental costs and mapping expenses that generally do not apply to services and meters).

In addition, if smart metering is in the process of being installed or has just been installed, O&M costs of smart meter installation may be part of accounts 586 and 587 in some historical years. In that case, it will be necessary to identify and remove those costs or use a historical period of time entirely after smart meter installation.

## 21.4 Billing and Customer Service Expenses

A marginal cost analysis of billing and customer service expenses is usually done in one of two ways. The most common way, following the NERA method, is to average costs over a number of historical and projected years. These costs are calculated per weighted customer, recognizing that certain activities are more heavily related to some customers than others. The second method is to use the costs of revenue cycle services, which are **short-run incremental costs** used to pay competitive service providers, plus similar short-run calculations for call centers and other activities. These costs are less than embedded costs of the same functions used in the NERA method. PG&E chose this method in Phase 2 of its 1999 general rate case to be consistent with the lower marginal costs it calculated for paying competitors; it has kept this design ever since. A method based on revenue cycle services is more consistent with a short-run marginal cost theory, but many utilities may not have the ability to implement it.

Many of the issues related to the appropriate calculation of marginal costs of billing and customer service are similar to the embedded cost issues raised in this manual. As with the discussion of this issue in Section 12.1, the frequency of billing and collection is driven by usage; if customers used minuscule amounts of power, it would not be cost-effective to read meters (without smart meters) or even bill on a monthly basis. For utilities without AMI, costs in excess of bimonthly meter reading and billing could be considered revenue-related rather than related to customer accounting. Relatedly, if smart meters are being implemented or have recently been implemented, meter reading costs from periods before smart meter implementation (as well as other costs such as call center costs associated with the implementation process) must be removed to prevent double counting of the capital cost of the smart meter and the operating cost of the mechanical meter that the smart meter replaces. As with embedded costs (see Section 12.3), the costs associated with major account representatives assigned to serve large customers (regardless of the FERC accounts in which they are found) should be considered part of the marginal costs of serving those customers and should be assigned to them.

As with customer-related distribution costs, in jurisdictions using long averages with both present and future costs, the future cost forecast must be reasonable. In the specific case of customer accounting costs, a trend toward declining costs and increasing productivity has persisted for almost a decade. More customers are receiving and paying bills online or through automatic bank transactions, both of which are less expensive to the utility than mailing bills and payment envelopes to the customer and then opening and processing return envelopes with payments from customers. Phone calls to the utility are being replaced with internet transactions (even for items such as changing service or making payment arrangements) and the use of interactive voice response units. Even though utilities may claim that the remaining calls may be more complex, customer service representatives are logging fewer total hours. As a result, it is important to examine any set of averaged costs carefully. If costs are declining, as they should be, then an average would include costs from a period of worse productivity than the present and should not be used. Similarly, if the future is projected to be more expensive than recent history, that assumption should be probed for reasonableness.

Some customer accounting and customer-related metering and distribution O&M expenses are paid by fees, not rates (see Chapter 15). As a result, they are not marginal costs associated with the general body of ratepayers. Costs of activities such as establishing service; disconnection and reconnection after customer nonpayment; field collections; meter testing; and returned checks are offset by fees received from individual customers (largely residential customers). If the costs paid by the fees are allocated heavily to residential customers, but the fees are not included in the revenue to be allocated, this would effectively cause residential customers to pay twice: once in the rate and a second time when assessed the fee. This problem can be dealt with in either of two ways. Nevada includes the fees in the revenue to be allocated and directly assigns the fees as revenues received from the classes that pay them. California generally removes an amount equal to the fees from the marginal customer accounting cost. The methods are not identical, but both will address the double counting. Costs (and uncollectible accounts if necessary) related to billing and collecting money from non-energy activities such as line extension advances and other products and services besides the utility's energy bills may be in accounts 901 through 905, but they are not marginal costs of serving electric customers and should be excluded from marginal customer costs. This is similar to the approach in Section 15.2 for embedded costs.

In some cases, the difference between marginal and embedded cost analysis is that costs are excluded from marginal costs while being allocated differently from other costs as embedded costs. Examples are economic development rates and uncollectible accounts expenses. Economic development rates, as well as any costs for marketing and load retention, are not marginal costs. These programs are not needed for customer service and theoretically should pay for themselves by attracting or retaining loads or improving economic conditions in the area. Uncollectible accounts expenses are not marginal costs associated with current bill-paying customers and conceptually should not be included in marginal costs. This is a similar issue to the embedded cost issue, discussed in Section 12.2, regarding whether uncollectible accounts expenses are costs associated with present customers (direct assigned) or former customers (allocated by usage or revenue). California regulators removed uncollectible accounts expenses from marginal costs in 1989 (California Public Utilities Commission, 1989); the Nevada commission includes them (Public Utilities Commission of Nevada, 2002, p. 109). If uncollectible accounts are included, then late payment revenues must be treated consistently, by adding them to the distribution revenues to be allocated and subtracting them from the classes that pay them.

Lastly, a number of cost elements that are sometimes mistakenly classified as customer service do not fit a marginal cost analysis well, particularly if the programs are undertaken for public policy reasons. A cost undertaken for public policy reasons is not a marginal cost, even if it might theoretically vary with the number of customers. An energy efficiency program or demand response program is established by the state or regulators for policy reasons, theoretically to provide a cost-effective or environmentally preferred substitute for other investments and expenses. Subsidy programs for low-income customers are also established for policy reasons. Certain other programs are also policy-related, such as promoting solar energy, battery storage and electric vehicles; allowing customers to opt out of smart meters; and research and development programs. These are not marginal costs, and their allocation to customers outside of a marginal cost framework will be discussed in Chapter 23.

## 21.5 Illustrative Marginal Customer Costs

Tables 42 and 43 on the next pages illustrate a calculation of marginal customer costs using the NCO and rental methods, with a set of assumptions that are generally realistic but not tied to any specific utility.

Table 44 on Page 213 shows the impact of the choice of marginal customer cost methods on the MCRR of distribution and thus on the overall allocation of distribution costs. To illustrate this impact, there is also an assumption as to demand distribution costs. Costs for primary customers are assumed to be lower than for other classes largely because they do not need line transformers. In this example, the residential class has 41% of the MCRR for distribution costs with the rental method but 38.8% with the NCO method.

**Table 42. Illustrative example of new-customer-only method for marginal customer costs**

| | Residential | Small commercial | Secondary large commercial | Primary industrial |
|---|---|---|---|---|
| **Initial investment** | | | | |
| Service | $800 | $1,200 | $3,000 | N/A |
| Meter | $200 | $300 | $3,000 | $9,000 |
| Total | $1,000 | $1,500 | $6,000 | $9,000 |
| **Present value of revenue requirements (PVRR) factor** | | | | |
| Service | 1.3 | 1.3 | 1.3 | 1.3 |
| Meter | 1.25 | 1.25 | 1.25 | 1.25 |
| **Investment with PVRR** | | | | |
| Service | $1,040 | $1,560 | $3,900 | N/A |
| Meter | $250 | $375 | $3,750 | $11,250 |
| Total | $1,290 | $1,935 | $7,650 | $11,250 |
| **New customers (% of system)** | 1% | 1% | 0.5% | 0% |
| **Replacements (% of system)** | | | | |
| Service | 0.5% | 0.5% | 0.5% | 0.5% |
| Meter | 2% | 2% | 2% | 2% |
| **Marginal cost for new customers** (investment with PVRR x new customer %) | | | | |
| Service | $10.40 | $15.60 | $19.50 | N/A |
| Meter | $2.50 | $3.75 | $18.75 | N/A |
| Total | $12.90 | $19.35 | $38.25 | N/A |
| **Marginal cost for replacement** (investment with PVRR x replacement %) | | | | |
| Service | $5.20 | $7.80 | $19.50 | N/A |
| Meter | $5.00 | $7.50 | $75.00 | $225 |
| Total | $10.20 | $15.30 | $94.50 | $225 |
| **Total investment marginal cost for new and replacement customers** | | | | |
| Service | $15.60 | $23.40 | $39.00 | N/A |
| Meter | $7.50 | $11.25 | $93.75 | $225 |
| Total | $23.10 | $34.65 | $132.75 | $225 |
| **Customer operations and maintenance cost** | $30 | $50 | $500 | $700 |
| **Total marginal customer cost** | $53.10 | $84.65 | $632.75 | $925 |
| **Number of customers** | 1,000,000 | 100,000 | 10,000 | 1,000 |
| **Marginal cost revenue requirement for customer costs** | $53,100,000 | $8,465,000 | $6,327,500 | $925,000 |

Table 43. Illustrative example of rental method for marginal customer costs

| | Residential | Small commercial | Secondary large commercial | Primary industrial |
|---|---|---|---|---|
| **Initial investment** | | | | |
| Service | $800 | $1,200 | $3,000 | N/A |
| Meter | $200 | $300 | $3,000 | $9,000 |
| Total | $1,000 | $1,500 | $6,000 | $9,000 |
| **Real economic carrying charge rate** | | | | |
| Service | 7% | 7% | 7% | 7% |
| Meter | 10% | 10% | 10% | 10% |
| **Annualized investment cost** | | | | |
| Service | $56 | $84 | $210 | N/A |
| Meter | $20 | $30 | $300 | $900 |
| Total | $76 | $114 | $510 | $900 |
| **Annual customer operations and maintenance cost** | $30 | $50 | $500 | $700 |
| **Total customer cost** | $106 | $164 | $1,010 | $1,600 |
| **Number of customers** | 1,000,000 | 100,000 | 10,000 | 1,000 |
| **Marginal cost revenue requirement for customer costs** | $106,000,000 | $16,400,000 | $10,100,000 | $1,600,000 |

Table 44. Illustrative comparison of rental versus new-customer-only method for overall distribution costs

| | Residential | Small commercial | Secondary large commercial | Primary industrial |
|---|---|---|---|---|
| **Marginal cost revenue requirement for customer costs** | | | | |
| Rental method | $106,000,000 | $16,400,000 | $10,100,000 | $1,600,000 |
| New-customer-only method | $53,100,000 | $8,465,000 | $6,327,500 | $925,000 |
| **Marginal distribution demand cost per kW** | $100 | $110 | $110 | $75 |
| **Demand per customer (kWs)** | 4 | 25 | 250 | 2,000 |
| **Number of customers** | 1,000,000 | 100,000 | 10,000 | 1,000 |
| **Marginal cost revenue requirement for distribution demand costs** | $400,000,000 | $275,000,000 | $275,000,000 | $150,000,000 |
| **Results: Rental method** | | | | |
| Total distribution marginal cost revenue requirement | $506,000,000 | $291,400,000 | $285,100,000 | $151,600,000 |
| Share of distribution costs | 41.0% | 23.6% | 23.1% | 12.3% |
| **Results: New-customer-only method** | | | | |
| Total distribution marginal cost revenue requirement | $453,100,000 | $283,465,000 | $281,327,500 | $150,925,000 |
| Share of distribution costs | 38.8% | 24.3% | 24.1% | 12.9% |

Note: Based generally on California examples, except transformer part of demand cost. Marginal demand cost is higher in commercial classes than residential because residential has more customers per transformer. Demand is lower in industrial class because no transformers or secondary lines are included. Percentages may not add up to 100 because of rounding.

# 22. Administrative and General Costs in Marginal Cost of Service Studies

Both A&G expenses and general plant costs are typically considered "loaders" to marginal costs, applied to the generation, transmission and distribution functions. Fundamentally, at least some A&G expenses and general plant costs are marginal costs, though over varying time horizons and in varying amounts because of economies of scale in running a large corporation.

The NERA method in the 1970s used an extremely long-run marginal cost method for A&G costs. It developed loading factors based on what appears to be a fairly arbitrary mix of labor, O&M expenses and total plant for A&G expenses, and it allocated general plant based on other plant (other capital investments). As with other elements of the NERA method, the mismatch in time frames is a serious theoretical concern. One method of addressing this is to eliminate consideration of joint and common A&G costs from the marginal cost analysis. This leaves only short-run marginal A&G costs as a better match with short-run generation marginal costs.

Short-run marginal costs include at least workers' compensation and pensions and benefits associated with other marginal costs that are labor-related. Similarly, incentive pay, to the extent recorded to A&G accounts, is a short-run marginal cost assigned to labor. Property insurance is a plant-related marginal cost to the extent that the amount of insured property affects the premiums.

If longer-term A&G costs are included, one can either include all of them as variable in the long run with the size of the utility or recognize potential economies of scale, which would mean that only a portion of costs is marginal. The best example of an intermediate-term marginal cost is the human resources department, which varies with the size of the workforce. Other examples of costs that will vary with the size of the utility in the intermediate term are benefits administration, accounts payable, payroll processing and capital accounting. Over a longer period, portions of an even broader set of costs are variable. For example, executive salaries are related (though possibly not proportional) to the size of the company, as a larger company will have more executives and pay them more (Marcus, 2010a, pp. 90-93 and Exhibit WBM-18). Other examples relate to buildings and other general plant items. A utility with fewer workers will own, rent and maintain less building space and have fewer vehicles and tools.

Recently a number of utilities, following the FERC method of unbundling transmission, have allocated both A&G expenses and general plant costs (using a long-run marginal cost basis) based on labor with the exception of (1) property insurance, which is based on plant, and (2) franchise fees based on revenue. The labor allocation method for A&G expenses tends to be less favorable to small customers than the plant-based method, but it has analytical merit. Key issues here are (1) ensuring that specific elements of A&G expenses are truly recurring marginal costs and (2) whether a given cost should be functionalized differently among generation, transmission and distribution. This can be as simple as, for example, removing a large one-time fire claim (which has no relationship to any cost drivers) from a utility's recorded A&G expenses and removing nuclear insurance from liability insurance allocated by company labor when the company had no labor costs at a jointly owned nuclear plant (Jones and Marcus, 2016, pp. 20-21). Or it can involve a more complex analysis of which specific A&G costs are marginal, an exercise Southern California Gas Co. undertook in its gas marginal cost studies (Chaudhury, 2015, pp. 21-22).

# 23. Public Policy Programs

There are a number of costs related to public policy decisions by state regulators that generally should not be considered marginal costs. Consideration should be given to allocating these costs separately from marginal costs. Many states have explicit cost allocations for public policy or energy efficiency costs that are separate from base rates or distribution rates. In California, energy efficiency costs are largely, though not entirely, allocated in proportion to total system revenues, with generation revenues imputed to customers who do not receive generation service from the utility so that direct access and community choice aggregation customers do not pay lower rates for public purpose programs than bundled customers with otherwise similar characteristics.[231] California allocates low-income rate subsidies in equal cents per kWh to all customers except municipal streetlights and those customers receiving the subsidies.[232]

However, some policy-oriented costs related to demand response programs and other items have been included in distribution costs, so that all customers, including those who may purchase generation from others besides the utility, can be required to pay for them. In these cases, the allocation of a cost such as demand response by an allocator such as a distribution equal percentage of marginal cost (EPMC) creates concerns. If costs of a demand response program that avoids generation are allocated by distribution EPMC (or even total EPMC), residential customers might be better off if the utility instead built generation of equivalent or, in some cases, higher cost, even if society would be worse off — because a smaller portion of the higher cost would be allocated to them. Even if a demand response cost is designed to avoid some T&D, the demand response measure generally will also reduce the need for generation capacity.

One framework used by consumer advocates in California applies different approaches to different subsets of public policy costs. It allocates the costs of direct programs that provide generation in distribution rates (e.g., interruptible and load management rate credits) by EPMC of generation (with generation marginal costs imputed to those not served by the utility). At the same time, it allocates programs that provide more broad public benefits (e.g., electric vehicle programs, research and development) or that create infrastructure to enable demand response (e.g., computer systems, the portion of AMI costs in excess of those that are cost-effective operationally for the distribution system) based on the equal percentage of revenue method discussed above for energy efficiency.

231 This method was essentially codified in A.B. 1890, California's restructuring legislation of 1996. Although the specifics of that legislation no longer apply, relatively similar methods have been used throughout the last two decades in a number of settled cases.

232 California Public Utilities Code § 327(a)(7): "For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an equal cents per kilowatt hour or equal cents per therm basis to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008."

# 24. Reconciling Marginal Costs to Embedded Costs

It is only happenstance if marginal costs and embedded costs produce the same revenue. This raises questions as to how to reconcile these items. The most common method allocates embedded cost revenue requirements in the same proportion that marginal costs are allocated. This is typically called the equal percentage of marginal cost method but may also be known as equiproportional.

There are two types of EPMC allocation. The first allocates the entire revenue requirement by the entire marginal cost revenue responsibility, called total EPMC allocation.[233] This method was used in both California and Nevada through the 1990s. Under this method, if generation marginal costs are low (because of excess capacity, renewable penetration, low gas prices or other reasons), more of the system costs are allocated based on distribution costs, which are allocated more heavily to small customers. The result is problematic for small consumers. This was particularly evident in California, where high costs in the 1980s — created by power purchase contracts required under PURPA and additions of nuclear power — were heavily allocated based on distribution costs because of excess capacity, low system incremental heat rates due to large amounts of baseload power, and falling gas prices that did not reflect the expectation at the time the excess capacity was being constructed.

A second problem with this total EPMC allocation method is that it does not work well in quasi-competitive markets. If some customers have market options to acquire generation and others do not, as in California and Nevada, using an EPMC method based on total marginal costs could distort competitive choices by setting generation rates based on a mix of generation, transmission and distribution marginal costs. As a result, both of these states now use an EPMC allocation by function. They separately allocate generation, transmission (in Nevada; California transmission used by investor-owned utilities is entirely under FERC jurisdiction) and distribution based on EPMC.[234]

The other less used approach for reconciling marginal costs to embedded costs is an economic approach known as Ramsey pricing and the resulting inverse elasticity rule.[235] Under this construct, any deviation from marginal costs creates an economic distortion. Advocates of this approach would reconcile marginal costs to embedded costs in the "least distortive" manner. At a high level this is reasonable, but there are many disputes about which choice is least distortive. Many advocates of this approach take a narrow view of societal costs and externalities and argue that the responsiveness of customer classes with respect to higher or lower costs — a concept known as elasticity of demand — is the key criterion. Relative elasticity of demand between rate classes, and between different rate elements for each rate class, is difficult to measure. Some advocates of the Ramsey pricing approach assume that residential customers are less responsive to changes in cost in the short term, particularly with respect to changes in the customer charge. But according to these advocates, if embedded costs are higher than the MCRR, then this leads to a larger share of costs being borne by residential customers, with those costs being recovered through higher customer charges for residential customers. These underlying assumptions may not have been true historically, but changing circumstances may weigh

233 The use of EPMC as a whole in California was first clearly adopted in 1986 (California Public Utilities Commission, 1986, pp. 636-646).

234 The unbundling of revenue allocation in California by function after the incomplete adoption of utility restructuring is discussed in Schichtl (2002). The functionalization of EPMC in Nevada is found in Public Utilities Commission of Nevada (2007, pp. 162-167).

235 This method was named after Frank B. Ramsey, who found this result in the context of taxation. Later, Marcel Boiteux applied the rule to natural monopolies in declining cost industries.

even more heavily against this approach in the future. If externalities are incorporated, then in many circumstances per-kWh rates are actually lower than the full societal marginal cost of consumption — meaning it would be socially efficient to classify incremental costs as energy-related. Full incorporation of externalities, in fact, argues for a differential approach depending on whether the MCRR is lower or higher than embedded costs, classifying any incremental costs as energy-related for inclusion in kWh rates while classifying any excess revenue as customer-related to provide a reduction in customer charges.

In addition, certain types of multifamily buildings often face a choice between master metering and individual meters. This choice affects the number of customers and overall customer charge revenue but has almost no effect on system cost other than meters and billing. The declining cost of storage and solar may enable growing numbers of customers to disconnect entirely from the grid as well. The experience in the cable television and telephone industries shows how people are willing to "cut the cord" to rely on nonmonopoly service providers. Lastly, even if the underlying claims from certain advocates of Ramsey pricing are correct, there are significant equity issues between classes at stake in the allocation of additional costs solely to the residential class. Similarly, using Ramsey pricing to pass those costs on through customer charges raises significant equity issues within the residential class, disproportionately affecting small users.[236]

236 It could be the case that lower-income customers have a more elastic demand to pay for electric service if prices are increased because of limited ability to pay.

# 25. Cutting-Edge Marginal Cost Approaches

It is important to sketch out a new paradigm for marginal costs, even though many of the calculations on which it could be constructed have not been developed.

The NERA method for calculating marginal costs, particularly for generation, becomes less sustainable as the utility systems move toward major technological change and reductions in carbon. While the effect may be different in different regions of the country, the short-term avoided energy cost will reflect diminishing variable costs to the extent that natural gas is replaced with renewables and storage. Capacity costs may be moving toward batteries given that renewable integration can be achieved better with storage resources that can both use overgeneration and provide ramping and integration more effectively than fossil-fueled plants that do nothing about overgeneration. Thus, it is important to at least sketch out a new paradigm for marginal costs, even though many of the calculations on which it could be constructed have not been developed yet or integrated into a whole.

## 25.1 Total Service Long-Run Incremental Cost

The basic theory presented here is the total system long-run incremental cost method that was developed in the telecommunications industry during its period of rapid technological change before deregulation. Under this method, all costs are variable but may be very different from historical costs. This is important when examining the generation system in particular, because the optimal system going forward is likely to have very few traditional variable costs.

The TSLRIC is theoretically defined as the total cost of building and operating an optimal new system to serve the current load with changes that can be reasonably foreseen and changes to reflect environmental priorities (e.g., additional efficiency and demand response, changes to electrification for purposes of decarbonizing existing fossil fuel end uses and development of more loads with storage or other controls). The system will be different from the current system in a number of ways. The theory is that it will be optimally sized with optimal technology, which should in most cases reduce costs (or at least societal costs reflecting environmental constraints) relative to current technology — although that may not always be true. However, the system would also be built at current construction costs, so it could be more expensive in that regard. Since TSLRIC represents an optimal system, it removes one of the key problems of the NERA method, which can disproportionately assign excess capacity to specific customer classes if not undertaken carefully to remove the excess capacity.

Although the theory is relatively easy to state, it has not been implemented for an electric utility, and the data to implement it will need to be collected and analyzed.
To make this calculation, one needs to start with the cost of the existing system. This is then adjusted for inflation since the time when it was built, yielding what is usually referred to as "replacement cost new." But a TSLRIC study goes beyond simply a study of the replacement cost of the system as it exists today. Other sources of data should be acquired for resources whose costs are declining due to technological change and data availability. From that point, one examines the changes in the generation resource mix to move it toward optimality. Substitution of storage or other DERs for upstream generation and transmission may reduce TSLRIC costs. A complex engineering analysis would also be required to review the magnitude of the cost-decreasing and cost-increasing drivers for transmission and distribution costs, which are likely to be different by utility. The discussion below outlines qualitative issues relating to the cost

changes that would result from using a system constructed under TSLRIC.

### 25.1.1 Generation

Without full quantification, an optimal system 15 to 20 years out will contain considerably more wind generation, solar generation, possibly some other renewable generation and more storage than the current system. The mix of solar and wind generation is likely to be region-specific, depending on available resources that can be economically brought to market. Some storage could be centralized, providing generation for peaking, ramping and renewable integration. At the grid level, storage could be related to batteries, compressed air and pumped hydro, as well as the load-related operations of large water projects (e.g., hydroelectric capacity and flexible pumping loads and storage associated with large water supply projects). The question of black start capability of storage resources may need to be addressed because, if storage can provide this capability, it may supplant the need for certain gas-fired resources.

Storage could be decentralized, also serving to reduce the need to build distribution capacity while serving the distribution system with greater reliability in addition to G&T displacement. At the decentralized level, batteries would be an option, but so would end-user storage such as controllable water heaters (which would have significant benefits for dealing with ramp), thermal energy storage to supplant peak air conditioning, and use of existing or new water storage to control timing of pumping and delivery by local water agencies and irrigators. This storage is a joint product that must be functionalized among generation, distribution and possibly transmission.

Controls on electric vehicle charging — to keep them out of peak periods, avoid distribution overloads, preferentially charge to mitigate ramp and possibly reverse flows (vehicle to grid) — could also create flexibility, since there would be little or no resource costs except controls (incremental changes in costs of charging and discharging only). These controls are installed at the end user level but may be critical to reduce generation and distribution costs in an optimal system and as such would be part of TSLRIC.

Other demand response programs beyond traditional programs (such as interruptible industrials and air conditioner cycling) likely would become cost-effective as part of an optimal system. Examples include smart appliances that would run discretionary loads such as washing, drying or dishwashing at times when the loads match system needs, and variable-speed drives for heating, ventilation and air conditioning systems that could both save energy and respond automatically to peak or ramp conditions. These also may be part of TSLRIC, functionalized among generation, transmission and distribution as joint products.

Most existing conventional hydro and pumped storage resources probably would remain part of an optimal system, although the timing of their usage may change from the current system. In part, even under TSLRIC, it is not reasonable to ignore high decommissioning costs that can be avoided by keeping them in operation. More importantly, hydro resources with storage also provide energy at zero incremental costs, as well as ancillary services and significant amounts of flexibility to the grid. These resources may be devalued rather than being included at full replacement cost to recognize that their continued operation depends in part on avoiding the costs of removing them — which is generally not considered in a TSLRIC environment. However, some smaller resources would be closed, particularly run-of-river plants and those in areas where there are significant environmental impacts. At current and projected costs (considering those related to capital, operations and emissions), coal and traditional nuclear units[237] likely would not be part of the new optimal system under TSLRIC.

The role of natural gas-fired generation for reliability and bulk energy generation in an optimal system that recognizes carbon constraints is a large question. In all likelihood, some of the most efficient gas generating units would remain for a significant period, although the amount of energy they produce could be considerably less than at present. Gas plants could include:

- CHP, which has very high efficiency and uses thermal energy to produce steam for industrial processes or chilled water to displace air conditioning loads.

237 Consider the abandonment of South Carolina Electric and Gas Co.'s Summer Nuclear Station and the cost overruns at Georgia Power's Vogtle units 2 and 3, which cost $23 billion — or more than $10,000 per kW (Ondieki, 2017).

- Combined cycle generation designed for flexible use that could also make up for any shortages in bulk energy if adverse weather conditions reduce output from hydro and renewables.
- Potentially, gas turbine peakers. The modern gas turbine supplanted less-efficient older gas-fired steam units. But storage and demand response are likely to make even modern gas turbines less economic, particularly for reserves, needle peak use and ramping.[238] Nevertheless, in some places, particularly where gas turbines are considerably cheaper than combined cycle units and where other flexible resources (such as hydro) are not widely available, there may be a dispatch range (for example, a 10% to 20% capacity factor) where gas turbines might be economic in an optimal system.

For any fossil generation, to the extent not otherwise internalized, a carbon adder based on residual damage or mitigation costs would be included under TSLRIC, but much of the TSLRIC system is being rebuilt to optimize for the need to reduce carbon emissions as well as for financial costs.

### 25.1.2 Transmission

Assuming no major technological advances (e.g., superconductors), some changes in transmission from the current system would arise from changing generation patterns. Long-distance transmission from existing coal and nuclear stations may no longer be part of an optimal system, but long-distance transmission from distant wind regions may replace it as a significant factor, either because of new construction or wheeling costs.[239] Interties would likely remain, although there may be more bidirectional power, and their role may be clearing renewable surpluses across wide regions. These transmission facilities for delivery of bulk energy, explicitly excluded from the NERA method, probably would be allocated over hours of use — making them energy-related, since they are not constructed for peak loads.

There may be other efficiencies associated with both better controls and with the possible use of strategically located storage devices if cheaper than both transmission lines and conventional RMR gas-fired generation. PG&E's use of batteries to displace an RMR contract in an area south of San Jose (discussed in Section 18.3) suggests the potential of this outcome. It is also possible that a further analysis of a more optimal network of transmission lines may reveal significant portions of those lines are, in fact, related to off-peak use or contingencies that could occur at nonpeak times and should thus be spread over more than peak hours.

### 25.1.3 Shared Distribution

The whole distribution system would become part of TSLRIC, instead of just the narrowly defined portions where the NERA method suggests investments are needed to serve increases in demand. The optimal distribution system is likely to need less capacity and to serve load more reliably and with fewer losses than the current system, because of technologies such as automatic switching and integrated volt/VAR controls — which would reduce costs — and because energy efficiency (particularly related to space conditioning), decentralized storage, demand response and controls on electric vehicles could reduce distribution peaks.

There are likely to be customers for whom usage is so low that they are better served by DERs than by a grid. They will include many rural customers (particularly in areas with high potential fire danger) but also small loads in an urban area. Solar-powered school crossing signals are being installed today, simply because the cost of connecting to the grid exceeds the cost of the distributed energy system. Other applications using low-wattage LED lights (e.g., traffic signals and remote streetlights) may ultimately also find a distributed alternative to be cheaper than grid service. Factoring this into a TSLRIC study will ensure that low-use customers are not assigned costs that will not benefit them economically.

Distribution is also likely to be bidirectional at least in some places, particularly if whole neighborhoods are served with distributed solar (or solar plus storage) resources. This change may require more expensive control systems in some

238 In 2018, NV Energy executed contracts for four-hour battery storage at a cost of $73 per kW-year, less than the carrying cost plus nondispatch O&M for a peaker (Bade, 2018).

239 For example, capacity freed up on transmission lines bringing coal-fired electricity from Four Corners to Southern California Edison is now being used to deliver wind energy from New Mexico. (Southern California Edison, 2015, p. 4).

places but is also likely to have a net effect of economizing on system sizing. Some primary distribution feeders (along with service lines and transformers) may need to be reconstructed if neighborhoods are converted from gas to electric space heating or if electric vehicles become ubiquitous, but those costs would be spread over more kWhs of load. Beneficial electrification of heating and transportation could increase total distribution costs, but because these technologies add energy loads, the costs per kWh may be stable or decline, and the amount of winter peaking load is likely to increase.

However, costs can increase from other aspects of the optimal distribution system. More of the optimal system is likely to be underground in urban areas, increasing system capital costs. Although overhead wires are cheaper, they also have nonmonetary costs related to worse aesthetics, poorer reliability (particularly in areas subject to ice storms and tropical storms) and to some extent worse safety (fires, downed wires). There would be some cost offset because the oldest and least reliable underground technologies that are currently being replaced at significant cost would have been supplanted, thereby reducing TSLRIC maintenance and replacement costs compared with current costs. Urban vegetation management costs would also be reduced in a system with more undergrounding. The overall costs of increased underground service (even after netting out the relevant costs avoided, such as maintenance, replacement of aging lines and vegetation management) likely would still be higher than current costs.

The optimal distribution grid is likely to have other cost-increasing features. It will need more resilience against natural disasters such as hurricanes, more patrols and maintenance to prevent fires, and costlier and more extensive vegetation management. It will also incur costs for protection against stronger winds, dealing with safety hazards from pole overloading by both electric utilities and communications companies, and possibly undergrounding in some remote areas to prevent outages and fires.

One potential outcome in the Western U.S. may even be that significant parts of the grid routinely begin to receive interruptible service to prevent wildfires. Even more remote portions of the grid serving few customers in areas with high fire danger may be completely abandoned. In essence, those parts of the system could be turned back to individual customers who use solar and storage to serve their loads and establish small microgrids. They may possibly be some of the last customers with fossil fuels (propane or compressed natural gas) as a source for meeting relatively large energy loads such as space and water heating in a mainly decarbonized system.

### 25.1.4 Customer Connection, Billing and Service Costs

The design of customer connection equipment may not change greatly, except for replacement of urban overhead lines with underground equipment and possibly some advances in controls that can optimize transformer capacity for small customers. As noted earlier, some service lines and transformers may need to be resized if neighborhoods are converted from gas to electric space heating or electric vehicles become ubiquitous. As with the current system, costs of advanced metering would need to be divided between the pure connection and billing function and the costs of other services that AMI provides (to reduce grid costs and to provide platforms for demand response and storage behind the meter).

Customer accounting and service O&M will be reduced due to the continuation of greater productivity from internet and interactive voice response systems and the prevalence of cheaper methods of receiving and paying bills that were discussed in Section 21.4. These items have been increasing productivity for the last decade and are likely to continue to do so.

## 25.2 Hourly Marginal Cost Methods

Although the hourly marginal cost method has not been explicitly used (a variant is used in Nevada), the Energy and Environmental Economics long-run marginal cost study points to how such a method could be used. Rather than dividing costs into demand and energy costs and allocating by kWs, E3 assigns its various types of avoided costs to individual hours so that specific energy efficiency, demand response and distributed generation costs could be measured against the hourly costs given their operational patterns. When costs are assigned to hours, the allocation to classes can be based on customer loads in those hours without calling the costs "demand" or "energy" costs. As with hourly allocation embedded cost methods, this may be an approach that will serve the cost analyst as the utility system evolves to include widespread renewable and distributed resources.

To convert the marginal costs calculated using a variant of the NERA method into hourly costs, and after considering the E3 hourly cost calculation, the following method could be used. This method still has some of the potential drawbacks of the NERA method discussed in detail above (possible mismatches in short-run and long-run analysis, failure to consider certain plant such as transmission interties, ambiguous treatment of replacement equipment, etc.). The NERA approach is also a fundamentally peak-oriented method, as opposed to the methods based on hours of use of capacity suggested in Chapter 17. Nevertheless, with some modification, it can be amenable to hourly calculations.

### 25.2.1 Energy and Generation

Energy costs can be calculated on a time period basis, as in Oregon or California. Otherwise, energy costs can be calculated on an hourly basis, as in Nevada, and aggregated into time periods based on hourly loads (including losses) by each class in each time period. Generation capacity costs need to be originally calculated in dollars per kW of capacity and divided between peaking capacity and other capacity needs (e.g., ramp) in ways described in Section 19.3. The peaking costs would be assigned to a subset of hours using methodologies such as loss-of-energy expectation, PCAF, loads or load differentials in largest ramp periods, or other multihour methods. Costs in each hour would then be calculated in cents per kWh and multiplied by the loads in each hour (including losses). The hourly costs can be aggregated into time periods. Consideration should be given to the establishment of a super-peak period for hourly cost allocation containing the highest peak-related costs based on loss-of-energy expectation or PCAF allocations to encourage the use of short-term resources such as demand response. If ramp costs are calculated, they could largely be based on storage operations and could have negative capacity costs in hours when storage is charging immediately before a ramp and positive capacity costs from the beginning of the ramp through the daily peak and shortly afterward.

### 25.2.2 Transmission and Shared Distribution

For transmission and distribution costs (except possibly for distribution costs for new business, including primary lines installed to connect new customers and transformers), a method that skips the dollars-per-kW step and goes directly to total dollars per hour has advantages. It avoids the significant problems associated with mismatches of kWs of capacity (calculated based on extreme weather peak loads or size of equipment that is added) and kWs of load (calculated based on a smaller number of kWs such as PCAF or a peak or diversified demand); see Appendix C. This also provides a clearer path toward design of TOU pricing. If a figure in cents per kWh is needed in an hour or time period, total dollars can be divided by the loads in each hour. Such an allocation method would need to be disaggregated by voltage (transmission if not FERC jurisdictional, possibly subtransmission, distribution). Additionally, a disaggregation at each voltage between substations and circuits would improve an hourly calculation because substations and circuits may have different time patterns of usage and cost causation.

For each component (excluding the transmission components for utilities with fully FERC jurisdictional transmission), the total investment in capacity-related equipment including automation and controls — unlike the NERA method, which excludes them — would be calculated in real dollars and averaged over a period such as 10 years. This should perhaps include both forward-looking and historical data as with the NERA method. The costs should then be annualized using an RECC and with O&M and possibly replacements added (in real dollars per year). The O&M and replacement costs would be based on either averaged costs or forward-looking costs if changes from the average have been observed or are expected.

Substation capacity needs are generally oriented to the peak loads of the equipment, although they are also related to the duration of heavy energy use, suggesting a broader allocation than a single coincident peak. An allocation of total dollar costs to time periods consistent with the NERA method's emphasis on capacity could be based on some hybrid of the percentage of kVA of substation peaks in each season and time period and a PCAF, which has an energy component because all loads in excess of 80% of the peak are assigned some capacity value. The PCAF could be set differently for summer and winter peaking kVA if applicable. For rate design purposes, a super-peak period could also be carved out that recognizes stress on components and high marginal line losses during extreme loads.

Transmission and subtransmission line marginal capacity under the NERA method involves a highly networked system, where at least some of the installed capacity is needed to meet contingencies that may occur at times other than during peak hours. The hourly causation and allocation of costs is likely to require further analysis that has not yet been conducted. But it could be some mix of peak loads (i.e., PCAF) and hourly loads (weighted into time periods when contingencies are most likely to occur to the extent possible).

Distribution substations are generally oriented to diversified peak loads on the equipment while also being related to the duration of energy use and should be allocated to hours in a manner like the allocation of transmission substations. Distribution lines are more radial in nature, although switching among feeders has been installed in some places, and more automation and volt/VAR controls are likely to cause distribution systems to become more networked. The cost causation for distribution line capacity has a peak-oriented component — which is likely to increase as the system networking and switching increases — and a component related to individual feeder peak loads, which is likely to decline. To allocate these costs to hours, one could start with a cost component for specific lines that would be directly assigned based on the individual peak of customers who are very large in relation to feeder sizes (i.e., customers over a particular MW size or a high percentage of the feeder's peak load). Remaining costs could be allocated to hours based on a mix of PCAF or top hours, a component based on the timing of individual feeder peaks (taking into account differences in residential and commercial load patterns) and a base load to all hours. For cost allocation, the hourly loads for feeder peaks could segregate the residential and commercial loads into different hours. If large customers are directly assigned costs, they would not be allocated any of the hourly costs.

New business distribution lines could be part of distribution circuits or could be segregated into a separate cost item for allocation. If new business lines and line transformers are separated from other distribution costs, the costs could be calculated in dollars per kW using a method with a demand measure such as changes in the demand at the final line transformer[240] (which reflects diversity for those customers sharing transformers). These costs can then be allocated to hours within each class based partly on class peak load characteristics (e.g., assigning more costs to residential customers in summer evening hours or to commercial customers during summer afternoons) and partly to additional hours to reflect that transformer performance is degraded if more energy is used in high-load (nonpeak) hours, as discussed in Section 5.1. A class allocation based on loads at the transformer would reflect that these very localized costs have some relationship to the customer's own demand (diversified to the transformer). Some utilities may have a small secondary distribution marginal capacity component reflecting that capacity may need to be added to networked secondary systems. This cost, if applicable, could be treated similarly to new business and line transformer costs, assigned in dollars per kW based on demand at the final line transformer and assigned to classes on the secondary system in the same way as line transformers.

O&M costs for substations and circuits generally should be allocated in the same way as the plant, except that costs of vegetation management and various periodic patrols and inspections should be assigned to all hours because they are not caused by peak loads.

If T&D replacement costs are included as recommended in Chapter 20, the costs should be allocated to hours either in a manner like the underlying allocation for plant of each type or based on all hours, reflecting that replacements are not based on peak demand. Some mix of the two methods may also be used.

240 With an allocation to primary voltage customers based on maximum demand but excluding transformer costs.

# 26. Summary of Recommendations for Marginal Cost of Service Studies

This chapter provides recommendations on two sets of issues: how to make incremental improvements to the predominantly used NERA method and how to work toward developing an hourly TSLRIC method, which has not yet been implemented.

## 26.1 Improving Marginal Cost Methods

Nine key items are distilled from Part IV as to how to improve marginal cost methods from the NERA method.

1. Analyze whether demand response can provide relief for the highest 20 to 50 hours of system load more cost-effectively than supply options, and substitute these costs for peak-hour costing if they are available and cost-effective.
2. Analyze whether grid-sized batteries are the least-cost capacity resource in the near term, instead of combustion turbine peakers, to meet the highest few hundred hours of system load — recognizing that they may take on a different role in the long term as systems become more heavily reliant on variable renewable generation. This is particularly important if reliability has a grid integration or ramping function as well as a peaking function in the relevant jurisdiction, because a battery can reduce ramp approximately twice as much as a generator of the same size and can smooth intermittent resource output better than a fossil-fueled plant.
3. Move toward long-run incremental costs for generation containing less carbon as a first step toward the TSLRIC method. Oregon uses 75% combined cycle and 25% solar in its long-run incremental cost. To the extent that it can be reasonably justified, a decarbonized long-run incremental cost would have storage for capacity, more renewables and less gas.
4. If the NERA-style short-run energy and generation capacity cost methods are used in the relevant jurisdiction, use a longer period of time for analyzing marginal energy costs than one to six years to deal with the mix of short-run and long-run costs currently used. Also ensure that carbon costs are included and a renewable portfolio standard adder is used if relevant to the jurisdiction. And examine whether pure capacity purchased from the market is cheaper than either a combustion turbine or battery for near-term application.
5. Make the definition of marginal costs more expansive for transmission and distribution to include automation, controls and other investments in avoiding capacity or increasing reliability, and consider including replacement costs.
6. Use the NCO method of calculating marginal customer costs. If replacement is included for any assets, a replacement rate should be based on actual experience, which would typically be less often than the accounting lifetime suggests.
7. Functionalize marginal costs in revenue reconciliation; use EPMC by function, not in total.
8. If demand costs are used, make sure that kWs used to calculate marginal costs and kWs used to allocate them are harmonized.
9. To the extent feasible, use an hourly method, such as the one E3 developed, to assign costs to hours and then to customer class loads. This avoids the need to separate costs into the demand and energy classification.

## 26.2 Moving Toward Broader Reform

TSLRIC will require both vision and research to be implemented for all utility functions. How a TSLRIC approach might look different from simply using replacement cost new for existing facilities was sketched out in Section 25.1.

The first place where a TSLRIC approach could be used is for generation, where it could be built up from a lower-carbon long-run incremental cost. Other resources may also be available to assist in constructing the TSLRIC of generation. They include the low-carbon grid study for the Western grid and similar studies that build out potential future resource plans (Brinkman, Jorgenson, Ehlen and Caldwell, 2016, and Marcus, 2016). This is a data-intensive approach that will require envisioning and costing out future systems and determining the resilience of the cost estimates to various assumptions. TSLRIC for generation probably suggests starting with a "cost by hours of use" approach, since there is only a limited amount of resources with fossil fuel that may not be dispatched in all hours. This means that price shapes based on short-run marginal cost may no longer make sense. This method would end up giving batteries and storage negative energy costs when they are charging and positive costs when discharging. Distributed generation would require functionalization.

Developing TSLRIC for transmission and distribution would require considerable amounts of engineering analysis to determine how the various cost drivers would work when developing a more optimal system and would likely involve a longer process.

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# Part V:

# After the Cost of Service Study

# 27. Using Study Results to Allocate the Revenue Requirement

Ultimately, the purpose of a cost of service study is to inform utility regulators about the relative contribution to costs by the various customer classes as one element in the decision on how to apportion the revenue requirement among classes. In most states, regulators have a great deal of discretion about how they use the results of cost allocation studies. Therefore, the way the results are presented is important because the regulators will want to see important impacts clearly to use their time efficiently.

Embedded cost of service studies and marginal cost of service studies approach this very differently, and we discuss each separately in this chapter. After that, we discuss approaches regulators use to implement, or diverge from, the results of these studies.

## 27.1 Role of the Regulator Versus Role of the Analyst

The role of the regulator is different from that of the analyst. Regulators typically are appointed or elected into the position based upon their broad perspectives of what "fair, just and reasonable" means in the context of utility regulation and pricing. These perspectives are necessarily subjective.

The analyst, on the other hand, may be tempted to work on a strictly scientific and mathematical basis. This may not adequately serve the needs of the regulator, who may need the analysis to take note of public policy goals, economic conditions in the service territory and other factors.

In the simplest terms, the regulator may need a range of reasonable options for cost allocation and for rate design, based on a range of reasonable analytical options, not a single recommendation based on a single framework or approach. The analyst must be prepared to develop more than one cost allocation study, based on more than one analytical approach, and let the regulator consider the principles guiding each study. The analyst must be prepared to develop multiple approaches to rate design, all sharing the same goals of overall revenue recovery and efficient forward-looking pricing.

## 27.2 Presenting Embedded Cost of Service Study Results

Embedded cost of service studies typically include conclusions regarding the relative margin to the utility from each customer class. Relative margin is a measure of profitability, based on the revenues, expenses and rate base allocated to each class.[241] Class profitability is often presented in the following forms:

1. Calculated rate of return on rate base (expressed both by class and for the total utility):

$$\text{rate of return} = \frac{\text{allocated annual operating income}}{\text{allocated rate base}}$$

   Where allocated annual operating income = annual revenues – annual allocated expenses

2. Calculated utility profit margin (expressed both by class and for the total utility):

$$\text{profit margin} = \frac{\text{annual revenues}}{\text{annual allocated expenses}} - 1$$

3. Ratio of class revenue to total class-allocated costs:

$$\text{revenue ratio} = \frac{\text{revenues}}{\text{allocated expenses + allocated return}}$$

   Where allocated return = allocated rate base x allowed rate of return

4. Revenue shortfall:

$$\text{shortfall} = (\text{allocated return + allocated expenses}) - \text{current revenues}$$

5. Percentage increase required for equal rate of return:

$$\text{increase for equal rate of return} = \frac{\text{shortfall}}{\text{revenues}}$$

Table 45 on the next page shows an illustrative example of the computation of these measures.

241 These computations may use historical revenues and costs or projected revenues and costs.

Table 45. Computing class rate of return in an embedded cost study

| | Total | Residential | Small (up to 20 kWs) | Medium (20 to 250 kWs) | Large (more than 250 kWs) | Large primary | Other |
|---|---|---|---|---|---|---|---|
| **Revenues** | $117,760,688 | $28,116,419 | $8,342,138 | $26,156,458 | $38,730,796 | $15,134,759 | $1,280,117 |
| **Allocated expenses** | $112,438,805 | $28,297,246 | $8,997,362 | $23,807,377 | $35,927,265 | $14,280,041 | $1,129,515 |
| **Operating income** | $5,321,883 | -$180,827 | -$655,223 | $2,349,081 | $2,803,532 | $854,718 | $150,603 |
| **Allocated rate base** | $87,878,094 | $24,935,855 | $8,339,503 | $18,481,728 | $26,069,711 | $9,399,629 | $651,667 |
| **Allocated return** | **$5,321,883** | **$1,510,111** | **$505,039** | **$1,119,251** | **$1,578,778** | **$569,240** | **$39,465** |
| **Rate of return** | 6.06% | -0.73% | -7.86% | 12.71% | 10.75% | 9.09% | 23.11% |
| **Profit margin** | 4.52% | -0.65% | -7.82% | 8.94% | 7.21% | 5.62% | 13.33% |
| **Revenue-cost ratio** | 100.00% | 94.33% | 87.79% | 104.93% | 103.27% | 101.92% | 109.51% |
| **Revenue shortfall (or surplus)** | | $1,690,938 | $1,160,262 | ($1,229,831) | ($1,224,754) | ($285,478) | ($111,138) |
| **Percentage increase for equal rate of return** | | 6.01% | 13.91% | -4.70% | -3.16% | -1.89% | -8.68% |

Note: Independent rounding may affect results of calculations.

To the extent that the results of the cost of service study are reliable, the class rates of return indicate which classes are paying more or less than the average return. In the example in Table 45, the rate of return results show that the utility is earning less than the average return from the residential class and the small general service class and more than average from the other classes. These class rate of return results do not provide much information about the size of the revenue shift that would produce equal rates of return (or any class-specific differential return requirement), or whether a negative rate of return represents a very serious situation.

The profit margin, while commonly used in many industries, ignores the return on capital. The revenue-cost ratio provides a more intuitive metric. The most useful results may be the revenue shortfall and the increase required to produce class return equal to the system average return.

These metrics show a very different picture of interclass equity. The residential class may be providing a negative rate of return, -0.73% in Table 45, but its revenues are equal to 94.33% of the system revenue requirement. Because of uncertainties in sampled load data, variation in load patterns among years and the difficulty of defining the causation of many costs, regulators define a "range of reasonableness" of one or more of the profitability metrics. For example, if the regulator considered reasonable the range of revenue-cost ratio from 93% to 107%, it is possible a regulator might find that the residential class is producing a reasonable level of revenue but that small general service customers should be paying a somewhat higher share of system costs than 87.79% and the "other" class (which might be mostly street lighting) should be paying somewhat less than 109.51%.

The cost allocation process usually assumes that all classes and all assets impose the same cost of capital. The results in Table 45 reflect that assumption, effectively stating that an equal return is the goal. In some cases, the regulator may determine that different customer classes impose different financing costs in percentage terms — for example, to reflect the higher undiversifiable risks of serving industrial loads through the economic cycle. In addition, some assets are riskier than others; generation is generally riskier than T&D, while nuclear and coal generation are often regarded as being riskier than other generation. In this situation, the cost of service study could be modified to reflect the differential risks (different required rates of return can be applied to different classes of customers or different categories of utility plant). Or the cost of service study results could be presented in a manner that allows the user to compare the achieved return to the class target return.

To summarize, presenting embedded cost of service study results in multiple ways is often helpful to regulators. The revenue-cost ratio is probably the easiest way for regulators to understand and use the results of cost of service studies in determining the fair, just and reasonable apportionment of costs. It is important to note that the result of this allocation process is to determine a level of revenue that the regulator deems cost-related. The regulator will often apply other non-cost criteria to establish the level of revenue that each customer class will pay.

## 27.3 Presenting Marginal Cost of Service Study Results

Marginal cost of service studies reach a very different set of conclusions than embedded cost of service studies. While an embedded cost of service study divides up the allowed revenue requirement among classes, a marginal cost of service study measures (over a short-, intermediate- or long-run time frame) the costs that would change as customer count and usage change.

A marginal cost of service study produces a cost for each increment of service: the cost of connecting additional customers, peak capacity at different levels of the system and energy costs by time period. These can be multiplied by customer usage to generate a marginal cost revenue requirement for each class. Table 46 shows an illustrative marginal unit cost result.

**Table 46. Illustrative marginal cost results by element**

| | Units | Cost per unit |
|---|---|---|
| **Customer connection** | Dollars per year | $80 |
| **Secondary distribution** | Dollars per kW | $40 |
| **Primary distribution** | Dollars per kW | $80 |
| **Transmission** | Dollars per kW | $50 |
| **Generation capacity** | Dollars per kW | $100 |
| **Energy by time period** | | |
| On-peak | Dollars per kWh | $0.10 |
| Midpeak | Dollars per kWh | $0.07 |
| Off-peak | Dollars per kWh | $0.05 |

Table 47 shows load research data for an illustrative utility system with three classes with identical kWh consumption but different per-customer usage and very different load shapes. The residential class and secondary commercial class both take power at secondary voltages, but the secondary commercial class has a more peak-oriented usage and 10 times the average consumption per customer.

**Table 47. Illustrative load research data for marginal cost of service study**

| | Units | Residential | Secondary commercial | Primary industrial |
|---|---|---|---|---|
| **Customer connection** | # of customers | 100,000 | 10,000 | 1,000 |
| **Secondary distribution** | kWs | 300,000 | 320,000 | N/A |
| **Primary distribution** | kWs | 303,000 | 325,000 | 250,000 |
| **Transmission** | kWs | 305,000 | 325,000 | 255,000 |
| **Generation capacity** | kWs | 307,000 | 330,000 | 258,000 |
| **Energy by time period** | | | | |
| On-peak | kWhs | 245,600,000 | 396,000,000 | 206,400,000 |
| Midpeak | kWhs | 614,000,000 | 825,000,000 | 825,000,000 |
| Off-peak | kWhs | 614,000,000 | 252,600,000 | 442,200,000 |
| All periods | kWhs | 1,473,600,000 | 1,473,600,000 | 1,473,600,000 |
| **Class load factor** | | 55% | 51% | 65% |

Table 48. Illustrative marginal cost revenue requirement

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Customer connection** | $8,000,000 | $800,000 | $80,000 | $8,880,000 |
| **Secondary distribution** | $12,000,000 | $12,800,000 | N/A | $24,800,000 |
| **Primary distribution** | $24,240,000 | $26,000,000 | $20,000,000 | $70,240,000 |
| **Transmission** | $15,250,000 | $16,250,000 | $12,750,000 | $44,250,000 |
| **Generation capacity** | $30,700,000 | $33,000,000 | $25,800,000 | $89,500,000 |
| **Energy by time period** | | | | |
| On-peak | $24,560,000 | $39,600,000 | $20,640,000 | $84,800,000 |
| Midpeak | $42,980,000 | $57,750,000 | $57,750,000 | $158,480,000 |
| Off-peak | $30,700,000 | $12,630,000 | $22,110,000 | $65,440,000 |
| **Total** | $188,430,000 | $198,830,000 | $159,130,000 | $546,390,000 |
| **Average marginal cost per kWh** | $0.128 | $0.135 | $0.108 | $0.124 |

The primary industrial class has a less peak-oriented usage and 100 times the average consumption per customer of the residential class.

Table 48 combines the marginal costs by element with the load research data to compute a marginal cost revenue requirement for each class, as well as the combined total.

As shown in Table 48, the illustrative MCRR for all classes combined is $546,390,000. It would be pure happenstance if this equaled the embedded cost revenue requirement determined in the rate case. More likely, the revenue requirement will be significantly more or less. The next step in a marginal cost of service study is reconciliation between the MCRR results and the establishment of class-by-class responsibility for the embedded cost revenue requirement.

There are two commonly used methods to reconcile the class marginal cost responsibility, as determined by a marginal cost of service study, to the utility embedded cost revenue requirement determined in the rate proceeding. The first method is equal percentage of marginal cost, which itself has two variants. The second is the inverse elasticity rule derived from Ramsey pricing. The approaches are very different.

In the EPMC approach, the embedded cost revenue requirement is compared with the total of the class marginal cost revenue requirements, also known as the system MCRR. For example, we offer two possible situations in tables 49 and 50 — one where the marginal cost is less than the revenue requirement, the other where it is more — and show the result of adjusting the revenue for each class by a uniform percentage. The class marginal cost revenue requirements

Table 49. EPMC adjustment where revenue requirement less than marginal cost

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Marginal cost revenue requirement** | $188,430,000 | $198,830,000 | $159,130,000 | $546,390,000 |
| **Embedded cost revenue requirement** | | | | $500,000,000 |
| **Ratio of embedded cost to marginal cost** | | | | 92% |
| **Reconciled revenue requirement** | $172,431,779 | $181,948,791 | $145,619,429 | $500,000,000 |

**Table 50. EPMC adjustment where revenue requirement more than marginal cost**

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Marginal cost revenue requirement** | $188,430,000 | $198,830,000 | $159,130,000 | $546,390,000 |
| **Embedded cost revenue requirement** | | | | $600,000,000 |
| **Ratio of embedded cost to marginal cost** | | | | 110% |
| **Reconciled revenue requirement** | $206,918,135 | $218,338,549 | $174,743,315 | $600,000,000 |

are adjusted by the ratio of the embedded cost revenue requirement to the system MCRR, resulting in the amount of the embedded cost revenue requirement that each class is responsible for. In Table 49, the cost responsibility for each class is reduced 8% below the marginal cost of service.

It is important to note that the result of this allocation process is to determine a level of revenue that the regulator deems cost-reflective. The regulator often will apply other non-cost criteria to establish the level of revenue that each customer class will pay.

The EPMC is often functionalized, particularly in jurisdictions where power supply is a competitive non-utility service. Assume for purposes of the illustration in Table 50 that the total embedded cost revenue requirement of $600 million comprises $400 million of generation costs, $60 million of transmission costs and $140 million of distribution costs. Table 51 shows how to reconcile costs for each function separately, which are then used to calculate the overall responsibility of each class for the embedded cost revenue requirement.

The illustrative functionalized EPMC results in Table 51 are close to the total EPMC results but slightly higher for

**Table 51. Illustrative functionalized equal percentage of marginal cost results**

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Distribution** | | | | |
| Customer connection | $8,000,000 | $800,000 | $80,000 | $8,880,000 |
| Secondary distribution | $12,000,000 | $12,800,000 | N/A | $24,800,000 |
| Primary distribution | $24,240,000 | $26,000,000 | $20,000,000 | $70,240,000 |
| Marginal cost revenue requirement | $44,240,000 | $39,600,000 | $20,080,000 | $103,920,000 |
| Embedded cost revenue requirement | | | | $140,000,000 |
| Reconciled distribution revenue requirement | $59,599,692 | $53,348,730 | $27,051,578 | |
| **Transmission** | | | | |
| Marginal cost revenue requirement | $15,250,000 | $16,250,000 | $12,750,000 | $44,250,000 |
| Embedded cost revenue requirement | | | | $60,000,000 |
| Reconciled transmission revenue requirement | $20,677,966 | $22,033,898 | $17,288,136 | |
| **Generation** | | | | |
| Capacity | $30,700,000 | $33,000,000 | $25,800,000 | $89,500,000 |
| Total energy | $98,240,000 | $109,980,000 | $100,500,000 | $308,720,000 |
| Marginal cost revenue requirement | $128,940,000 | $142,980,000 | $126,300,000 | $398,220,000 |
| Embedded cost revenue requirement | | | | $400,000,000 |
| Reconciled generation revenue requirement | $129,516,348 | $143,619,105 | $126,864,547 | |
| **Total reconciled revenue requirement** | $209,794,006 | $219,001,733 | $171,204,261 | $600,000,000 |

Table 52. Total EPMC results with lower marginal generation costs

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Marginal cost revenue requirement** | $133,170,000 | $137,240,000 | $103,720,000 | $374,130,000 |
| **Embedded cost revenue requirement** | | | | $600,000,000 |
| **Ratio of embedded cost to marginal cost** | | | | 160% |
| **Reconciled revenue requirement** | $213,567,476.55 | $220,094,619.52 | $166,337,903.94 | $600,000,000 |

residential and slightly lower for primary industrial customers.

However, if the marginal generation costs are considerably lower, functionalization can have a different impact. Assume that marginal energy costs are half of the estimates in Table 48 and marginal generation capacity costs are 80% of those in Table 48 (e.g., because of low gas prices, a shorter time horizon for cost estimation and excess capacity). These results are shown in tables 52 and 53.

As shown in Table 53, functionalization blunts the impact of lower marginal generation costs. Compared with Table 52, the residential class actually has a lower share of the embedded cost revenue requirement under functionalization with lower marginal generation costs. Table 54 on the next page compares the results for the residential class from tables 50, 51, 52 and 53.

Comparing the two functionalization scenarios, the residential share of embedded costs ends up very slightly higher in the lower marginal generation scenario, but the difference is less than 1%.

The second general approach used for marginal cost of service study application is the inverse elasticity rule.

Table 53. Functionalized EPMC example with lower marginal generation costs

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Distribution** | | | | |
| Customer connection | $8,000,000 | $800,000 | $80,000 | $8,880,000 |
| Secondary distribution | $12,000,000 | $12,800,000 | N/A | $24,800,000 |
| Primary distribution | $24,240,000 | $26,000,000 | $20,000,000 | $70,240,000 |
| Marginal cost revenue requirement | $44,240,000 | $39,600,000 | $20,080,000 | $103,920,000 |
| Embedded cost revenue requirement | | | | $140,000,000 |
| Reconciled distribution revenue requirement | $59,599,692 | $53,348,730 | $27,051,578 | |
| **Transmission** | | | | |
| Marginal cost revenue requirement | $15,250,000 | $16,250,000 | $12,750,000 | $44,250,000 |
| Embedded cost revenue requirement | | | | $60,000,000 |
| Reconciled transmission revenue requirement | $20,677,966 | $22,033,898 | $17,288,136 | |
| **Generation** | | | | |
| Capacity | $24,560,000 | $26,400,000 | $20,640,000 | $71,600,000 |
| Total energy | $49,120,000 | $54,990,000 | $50,250,000 | $154,360,000 |
| Marginal cost revenue requirement | $73,680,000 | $81,390,000 | $70,890,000 | $225,960,000 |
| Embedded cost revenue requirement | | | | $400,000,000 |
| Reconciled generation revenue requirement | $130,430,165 | $144,078,598 | $125,491,237 | $400,000,000 |
| **Total reconciled revenue requirement** | $210,707,823 | $219,461,226 | $169,830,951 | $600,000,000 |

Table 54. Residential embedded cost responsibility across four scenarios

| | High generation marginal costs | Low generation marginal costs |
|---|---|---|
| **Total EPMC results** | $206,918,135 | $213,567,477 |
| **Functionalized EPMC results** | $209,794,006 | $210,707,823 |

As discussed in Chapter 24, it is based on Ramsey pricing, an economic theory that efficiency is enhanced when the elements of the rate that are "elastic" with respect to price are set equal to some measure of marginal cost, and that adjustments to reconcile the revenue requirement should be applied to the least elastic component or components in order to maximize economic efficiency. This approach was popular during the era when marginal costs were significantly higher than average costs reflected in the revenue requirement.[242] For that reason, we show the application of the inverse elasticity rule only for a situation where the revenue requirement is lower than system marginal costs.

The least elastic element of utility service is often deemed to be the connection to the grid: the customer-related component of costs such as billing and collection, and the secondary service lines to individual structures. Evidence suggests this to be true historically. Whether utilities assess a monthly customer charge of $5 or $35, nearly all residences and businesses subscribe to electric service, although customer charges likely influence decisions whether to master-meter multifamily buildings, accessory dwelling units and offices. Economists generally agree that price more significantly influences actual customer usage of kWs and kWhs.

This may become significantly different where customers have more feasible choices to disconnect from the grid or obtain some services from on-site generation and storage. For example, pedestrian crossing signals often are now being installed with solar panels and batteries, without any connection to the grid. This phenomenon potentially could extend to larger users, depending on the levels of monthly customer charges, usage-related charges, and solar and storage costs.

Table 55 shows a marginal cost reconciliation of the same costs in Table 49 but by first reducing the customer and secondary costs by class and then applying an EPMC adjustment to the residual class marginal costs until the revenue requirement is reached.

In this illustrative example, the residential class benefits substantially and the secondary commercial class benefits somewhat compared with the straightforward application of the EPMC method in Table 49. As a result, the primary industrial class ends up paying a larger share of the overall embedded cost revenue requirement.

Table 55. Use of inverse elasticity rule

| | Residential | Secondary commercial | Primary industrial | Total |
|---|---|---|---|---|
| **Marginal cost revenue requirement** | $188,430,000 | $198,830,000 | $159,130,000 | $546,390,000 |
| **Customer connection costs** | $8,000,000 | $800,000 | $80,000 | |
| **Secondary distribution costs** | $12,000,000 | $12,800,000 | N/A | |
| **Adjusted marginal cost revenue requirement** | $168,430,000 | $185,230,000 | $159,050,000 | $512,710,000 |
| **Embedded cost revenue requirement** | | | | $500,000,000 |
| **Ratio of embedded cost to adjusted marginal cost** | | | | 98% |
| **Reconciled revenue requirement** | $164,254,647 | $180,638,178 | $155,107,176 | $500,000,000 |

242 Until the early 1980s, for example, Oregon excluded customer and joint costs from the marginal cost reconciliation process on the theory that these were highly inelastic components of customer demand — to simply be connected to the system. When overall rates rose and later costs declined, Oregon moved to an EPMC approach (Jenks, 1994, p. 12).

## 27.4 Gradualism and Non-Cost Considerations

This section discusses the methods regulators use to reach a decision on the fair apportionment of the revenue requirement based on both cost and non-cost considerations. Regulators frequently depart from the strict application of cost of service study results. Often, regulators reject the studies that are presented due to inclusion of one or more allocation factors they find unacceptable. A common example is the use of the minimum system method to measure a customer-related share of electric or gas distribution system costs; many regulators have found this methodology as unacceptable today as Bonbright did in 1961. In many cases where multiple studies are presented, the regulator may choose a result that reflects the "range of reasonableness" these studies suggest. In many cases where regulators do accept the results of a specific cost of service study, they may choose to move only gradually in the direction of the accepted study results.

It is quite common for regulators to consider the results of multiple cost of service studies in determining an equitable allocation of costs among customer classes. This can occur in various ways:

- Considering multiple embedded cost of service studies or marginal cost of service studies using different classification or allocation methods, to determine a range of reasonableness.
- Considering both embedded cost of service studies as an indicator of current costs and marginal cost of service studies as an indicator of cost trajectories in setting a reasonable cost allocation.

For example, in one docket, the Washington Utilities and Transportation Commission compared results of four cost of service studies before making a decision on cost allocation, with the results shown in Table 56 (1984, p. 46).[243]

**Table 56. Consideration of multiple cost of service studies**

| Source of study | Revenue as percentage of revenue requirement by class | | | |
|---|---|---|---|---|
| | Residential | Small general service | Large general service | Extra large general service |
| **Utility** | 91% | 113% | 110% | 108% |
| **Industrial advocate** | 91% | 112% | 110% | 110% |
| **Consumer advocate** | 93% | 115% | 105% | 104% |
| **Low-income advocate** | 97% | 113% | 103% | 99% |

Source: Washington Utilities and Transportation Commission. (1984). Cause U-84-65, third supplemental order in rate case for Pacific Power

Based on multiple studies using widely different methodologies for the classification and allocation of generation, transmission and distribution costs, the commission was able to determine a fair allocation of the revenue requirement responsibility, taking into account specific elements within each study where it ruled for or against those elements. The end result of multiple studies produced a range of reasonableness in the allocation of costs. The commission adjusted revenues gradually toward the common result of the studies: that residential customers were paying slightly less than their share of costs and that small and large general service customers were paying slightly more than their share.

Gradualism is the movement only partway toward the results of cost of service studies in apportioning the revenue requirement based on an accepted cost study. If a cost of service study indicates that a class is paying much less than its fair share of the revenue requirement, immediately moving it to pay its full share of allocated costs may result in excessive financial pain and dislocation for the affected customers. Regulators sometimes impose generic limits on rate changes (such as limiting the increase for any class to 150% of the system average increase) and often impose ad hoc limits, based on the facts of the case.[244]

243 Similarly, the Wisconsin Public Service Commission has routinely reviewed multiple cost of service studies and selected a revenue allocation without specifically relying on any one study. See Wisconsin Public Service Commission (2016, pp. 31-32): "As a result, the Commission finds that it is reasonable to continue its long-standing practice of relying on multiple models, as well as other factors, such as customer bill impacts, when determining the final allocation of the revenue requirement."

244 Where this sort of guideline takes the form of "no class will be assigned more than twice the rate increase applied to any other class," it is known as 2:1 gradualism.

There are several reasons a regulator will move gradually, including:

- To avoid rate shock on any individual customer class. Rate shock is often defined as a rate increase of more than 5% or 10% at any one rate adjustment. There is no firm standard, but many regulators hesitate to impose a rate adjustment that upsets the budgets of households or businesses. If an accepted cost of service study (or group of studies) suggests that one class should receive a 15% rate increase while others require no increase, a regulator may reasonably determine to spread the rate increase across all classes in a way that avoids rate shock within any one.
- To recognize that the cost of service study is a snapshot and that costs and cost responsibility may shift over time. The allocation of cost may vary significantly from one year to another because of factors such as fluctuating weather (which may change the peakiness of load, shift highest loads from summer to winter or dramatically change irrigation pumping loads). Under these circumstances, shifting revenue requirements back and forth among classes in each rate proceeding will not improve equity. Unnecessary volatility in prices may confuse customers, complicate budgeting and create unnecessary political and public-relations problems.
- To avoid overcorrecting a temporary imbalance in revenue responsibility, in recognition that technology is evolving and the cost structure will be different in the future. Cost of service studies measure costs based only on either test-year results of operations (embedded cost of service studies) or an estimate of future costs (marginal cost of service studies) at the time they are produced. Costs change dramatically over time as fuel costs change, new technologies become available and older assets shift to new roles. For example, the study may reflect the costs of legacy steam-electric generation scheduled for retirement in the next few years, to be replaced by demand response measures and distributed storage, which will also have T&D benefits.
- To avoid perceptions of inequity and unfairness. Bonbright (1961) identified perceptions of equity and fairness as a core principle of rate design, but they represent an overwhelmingly subjective metric. Many regulators, for example, have declined to reduce rates for any customer class in the context of an overall increase but may apply a lower increase to some classes than others. This is a matter of judgment, so this manual cannot provide any policy guidance on the right approach.

Each of these factors may represent a reasonable basis for deviating from precise recovery from each customer class of its full allocated cost. Legislatures generally grant regulators a great deal of flexibility in determining rates that are fair, just and reasonable and expect them to consider such factors in their decisions.

In addition to the principles of gradualism discussed in this section, many regulators consider non-cost factors in determining a fair apportionment of costs, including:

- Retention of load that cannot (or will not) pay for its fully allocated cost but can pay more than its incremental cost and thus can reduce the revenue requirement borne by other classes. Examples include electric space heat customers in summer-peaking utilities, irrigation customers in winter-peaking utilities and industrial customers facing global competition. Utilities frequently develop load retention tariffs to keep those customers on the system, contributing to paying off embedded costs. Charging full embedded cost to those tariff classes could result in higher, not lower, bills for other customers if the price-sensitive customers depart the system.

  The objective in those cases is to maximize the benefits to the customers paying full cost, without any particular concern about the interest of the class paying the reduced rate. If faced with the potential loss of a major industry, a regulator may opt to offer a rate significantly below the cost basis that would otherwise apply. Some, for example, have relied on an embedded cost of service study to determine the general allocation of costs among classes but relied on a short-run marginal cost of service study to determine a "load retention" or "economic development" rate to retain or attract a major customer. This is often done in recognition that failure to do so would result in the loss of sales, not to mention broader harms (e.g., increased unemployment) to the jurisdiction. The loss of sales could trigger a difficult regulatory decision on whether to apportion the surplus capacity that results among the remaining customers or to impose a regulatory disallowance on the utility, forcing utility investors to absorb the stranded asset costs.

- Serving loads that would otherwise impose higher environmental costs of alternative fuels. Examples include shore-service rates to discourage ships from running their high-emitting onboard generation while in port, special rates to displace on-site diesel generation and special rates for irrigators that would otherwise use diesel-powered pumps.
- Protection of vulnerable customers, for their own sake. Utilities, regulators and even legislatures seek to reduce the burden on groups of customers that are financially stressed. Most frequently, the target group is low-income residential customers, but the same approach is applied in some places for agricultural customers, important employers facing competition from outside the service territory and the like.

It is beyond the scope of this manual to attempt to identify the entire variety of non-cost factors a regulator may consider. The process of cost allocation does not occur in a vacuum but rather in the context of broader social and political currents.

# 28. Relationship Between Cost Allocation and Rate Design

At its heart, cost allocation is about equity among customer classes. Rate design has a different set of goals.

As indicated at the outset, cost allocation is the second of three steps in the rate-making process, beginning with the determination of the revenue requirement and ending with the design of rates. This manual has been careful to explain that these are separate phases of a proceeding and may have separate principles that apply, and the results may not always flow neatly from one phase to the next.

At its heart, cost allocation is about equity among customer classes — providing an analytical basis for assigning the revenue requirement to the various classes of customers on a system. This may be done strictly on the basis of an analytical cost of service study or, more often, using quantitative cost of service studies as a starting point, with broader considerations including gradualism, economic impacts on the service territory and attention to changes anticipated in future costs.

Rate design has a different set of goals. Rates must be sufficient to provide the utility with an opportunity to recover the authorized revenue requirement, but rate design is also about equity among customers within a class and about understandable incentives for customers to make efficient decisions about their consumption that will affect future long-term costs. It is common for a regulator to use a backward-looking embedded cost allocation method and a forward-looking rate design approach that considers where cost trajectories will go. Rate design can also incorporate public policy objectives, including environmental and public health requirements. In *Smart Rate Design for a Smart Future* (Lazar and Gonzalez, 2015), RAP articulated three principles for modern rate design:

- Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Principle 2: Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- Principle 3: Customers that supply power to the grid should be fairly compensated for the full value of the power they supply.

These principles provide guidance on how to modernize rate design, in conjunction with the traditional considerations of customer bill impacts and understandability.

## 28.1 Class Impacts Versus Individual Customer Impacts

The data used to examine changes in overall costs and bills for rate design are often much more granular, among types of customers, than data used for cost allocation.

Most cost allocation studies group customers into a relatively small number of classes for analysis. This is done for analytical simplicity, to provide the regulator a general guide to cost responsibility among the classes. Some do this grouping by voltage level, some by type of customer (e.g., residential vs. commercial vs. irrigation), but nearly all utilities have more individual tariffs than classes examined in the cost of service study. For example, "residential" may be a single class in the cost of service study, but separate tariffs may apply to single-family, multifamily, electric heating, electric water heating and electric vehicle loads. A utility may have a default rate design (e.g., inclining block) and one or more optional rate designs (e.g., TOU or seasonal customers). "Secondary general service" may be a single class in the cost of service study including all secondary voltage business customers that are nonresidential but will include urban commercial retail and office customers, as well as rural agricultural customers.

It is common to have separate rate tariffs that focus on the usage by specific groups of customers to enable them to control their bills by focusing their attention on elements of their consumption they can easily manage. A cost of service study provides broad guidance on how costs should be apportioned among customer classes. The result may be a uniform percentage allocation of a rate increase (or decrease) or one that is differentially apportioned among the customer classes.

The class definitions for cost allocation typically look at large groups of customers with similar service characteristics. Rate design often looks at smaller groups of customers with similar usage characteristics or even individual customers. For example, a shift of rate design from an inclining block rate to a time-varying rate may result in sharp increases in the bills for some customers with low usage.

The municipal utility for Fort Collins, Colorado, encountered this situation in its 2018 rate review and included a "tier charge" for all usage over 700 kWhs in part to avoid this kind of impact. The cost of service study did not contain sufficient detail to provide an analytical framework for this decision, but the rate design analysis showed that apartment residents and other small users would be adversely affected without this consideration of customer impacts. Similarly, when the Arizona Corporation Commission adopted inclining block rates in the 1980s for Arizona Public Service Co., it also created optional residential TOU and demand-charge rates to provide a pathway for larger residential users to avoid sharp bill impacts by shifting usage to lower-cost periods.

## 28.2 Incorporation of Cost Allocation Information in Rate Design

It is often the case that the information developed in the process of cost allocation is relevant to important issues in rate design. In most states, embedded cost of service studies are used to allocate costs among customer classes,[245] but regulators consider long-run marginal costs, either implicitly or explicitly, in designing rates within classes. The Washington Utilities and Transportation Commission stated in adopting an embedded cost framework that it wanted to be looking ahead in some parts of the rate-making process:

> In order to obtain forward-looking embedded costs which are required by the generic order, it is necessary to use historical cost for allocation to production plant and other categories, followed by a classification method which recognizes the current cost relationships between baseload and peak facilities (1982, p. 37).

This mix of embedded cost principles for cost allocation and marginal cost principles for rate design reflects a sense of balance between the notions of equity of overall cost allocation between classes and efficiency of rates applied within classes. Even in states where the embedded cost of service study does not contain any time differentiation of generation, transmission or distribution costs, regulators have adopted time-varying retail rates for many classes of customers to encourage behavior expected to reflect forward-looking and avoidable costs.

Although marginal cost of service studies typically do differentiate between time periods, even these studies provide limited guidance for rate design, simply because the factors that affect utility system design and construction may not be understandable to consumers. The core principles from Bonbright and many others — that rates be simple, understandable and free from confusion as to calculation and application — remain important, no matter what the results of a cost study may suggest. As a result, further refinements to this information may be necessary to apply in rate design.

Many analysts who still use legacy cost allocation techniques or otherwise problematic methods argue that this analysis is relevant to rate design. In most cases, this is doubling down on a mistake. For example, use of the minimum system method for determination of residential customer charges is a mistake because it greatly overstates the cost of connecting a customer to the grid. However, some

245 As discussed in Section 6.1, there is a direct relationship between an embedded cost of service study and the revenue requirement, which makes it an analytically convenient method of dividing the revenue requirement. Using a marginal cost of service study for cost allocation requires additional adjustments to ensure the correct amount of revenue will be recovered.

states allow use of the minimum system method for cost allocation between classes but require the narrower basic customer method for the determination of customer charges within classes in the rate design process.

## 28.3 Other Considerations in Rate Design

Regulators often include non-cost considerations in the design of rates. This is an appropriate exercise of their responsibility to ensure that rates are fair, just and reasonable. These terms are, by their nature, subjective, with ample room to include considerations other than electric utility costs in the ultimate decisions. For example, the Washington Utilities and Transportation Commission has stated:

> We recognize the substantial elements of judgment which are involved in the development of any cost of service study. We also recognize that many factors beyond an estimate of cost of providing service are important in the design of rates. These factors … include acceptability of rate design to customers; elasticities of demand, or the variation of demand when prices change; perceptions of equity and fairness; rate stability over time; and overall economic circumstances within the region.
>
> Based upon all these factors, we believe it is necessary to make some movement toward the cost of service relationships which the respondent has presented, although we do not believe that it is appropriate to fully implement the study in this proceeding. For policy reasons, including those stated above, we do not feel it necessary to infer that any cost of service study should be automatically or uncritically accepted and applied in rate design (1981, p. 24).

Some jurisdictions also explicitly incorporate broader societal costs, particularly environmental and public health externalities, into rate design decisions. In Massachusetts, the Department of Public Utilities has longstanding principles of efficiency that include: "The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means that it is cost-based and recovers the cost to society of the consumption of resources to produce the utility service" (Massachusetts Department of Public Utilities, 2018, p. 6).

These types of broader policy priorities can be reflected in many ways. For example, a state with a policy to encourage customer-owned renewable energy supply may develop rates that are favorable to customers with solar panels. A state with a policy to encourage energy conservation may have an additional reason to adopt inclining block rates. A state with real or perceived peak load limitations may prefer a critical peak pricing rate.

One very common public policy goal is the use of postage stamp rates, with the same rates applying to all customers of a class within a service territory. As discussed in Section 5.2, there are trade-offs in terms of the number of customer classes. A larger number of customer classes may capture more cost-based distinctions than a smaller number. For example, in most utility systems, multifamily customers that are less expensive to serve pay the same rates as single-family customers, and rural customers pay the same rates as urban. Having separate customer classes to reflect these distinctions would arguably lead to a much more equitable distribution of costs. These are probably the largest deviations from cost principles in today's utilities — dwarfing other deviations such as perceived undercharging of residential customers as a class or of solar customers as a subclass.

However, additional customer classes can lead to additional administrative and oversight costs. Furthermore, regulators, utilities and stakeholders must all have confidence that there are true cost differentials among the customer types and that there will be little controversy in applying these differentials. Some analysts object to customer classes based on adoption of particular end uses, although this may serve as a proxy for significantly different usage profiles. Some analysts may prefer separate classes for distinct types of customers, such as schools and churches. As discussed previously, rates that automatically reflect cost distinctions (e.g., time-varying rates or different residential customer charges for single-family and multifamily) can accomplish the same objective as the creation of additional customer classes, often with additional efficiency benefits from improved pricing.

Proper data must be available so all parties can scrutinize whether distinctions made between customer classes are based on cost and not improper motives like price discrimination.

Proper data must be available to all parties so they can scrutinize the distinctions made between customer classes and whether these are truly based on cost and not improper motives like price discrimination. Some analysts feel that a smaller number of rate classes will be fairer on balance, and many equity issues within a customer class can be dealt with through rate design.

Other common non-cost considerations come into play in designing rates for low- and limited-income consumers. In an engineering sense, these customers may differ very little from other residential consumers in the metrics typically used in a cost of service study. But regulators, on their own initiative or under direction from their legislatures, may adopt non-cost-based discounts for these customers. The same non-utility cost principles often apply to special rates for new industrial customers to encourage economic development within a service territory.

Lastly, in some states, legislatures have dictated some elements of rate design, constraining the discretion of the commission. In Connecticut and California, statutory limitations on residential customer charges dictate, respectively, the basic customer method[246] and a cap of $10 a month adjusted for inflation.[247]

246 See Connecticut General Statutes, Title 16, § 16-243bb, limiting the residential fixed charge to "only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service."

247 California Public Utilities Code § 739.9(f).

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# Conclusion

Cost allocation is a complex exercise dependent on sound judgment. No less an authority than the U.S. Supreme Court has made this point:

> A separation of properties is merely a step in the determination of costs properly allocable to the various classes of services rendered by a utility. But where, as here, several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[248]

These words from Justice William Douglas are just as applicable today as they were when written in 1945. What has changed since 1945 are the facts, which in turn require new judgments. In particular, advancements in technology have had a great impact and reverberating effects on our power system. Multiple aspects of our power system are continuing to evolve, and cost allocation methods must change to reflect what we are experiencing. Over the past few decades, key changes in the power system that have consequences on how we allocate costs include:

- Renewable resources are replacing fossil-fueled generation, substituting invested capital in place of variable fuel costs.
- Peaking resources are increasingly located near load centers, eliminating the need for transmission line investment to meet peak demand served by peaking units. Long transmission lines are often needed to bring not only baseload coal and nuclear resources but also wind and other renewable resources, even if they may have limited peaking value relative to their total value to the power system.
- Advanced battery storage is a new form of peaking resource — one that can be located almost anywhere on the grid and has essentially no variable costs. The total costs of storage still need to be assigned to the time period when the resource is needed, to ensure equitable treatment of customer classes.
- Consumer-sited resources, including solar and storage, are becoming essential components of the modern grid. The distribution system may also begin to serve as a gathering system for power flowing from locations of local generation to other parts of the utility service territory, the opposite of historical top-down electric distribution.
- Short-run variable costs are generally diminishing as capital and data management tools are substituted for fuel and labor.

Simply stated, this means that many of the cost allocation methods used in the previous century are not appropriate to the electric utilities of tomorrow. As we've discussed in this manual, new methods, new metrics and new customer class definitions will be needed. The role of the cost analyst remains unchanged: We are assigned the task of determining an equitable allocation of costs among customer classes. The methods analysts used in the past must give way to new methods more applicable to today's grid, today's technologies and today's customer needs.

This manual has identified current best practices in cost allocation methodology. These will also need to evolve to keep up with the technological changes our electric system is experiencing. Perhaps the most important evolution in methodology recognizes that utility grids are built for the general purpose of providing electricity service. The largest single cost of building the grid is to ensure that it provides kWhs to customers during all hours of the day and night. Thus, similar to the way we price gasoline, groceries and clothing, most costs of the grid should be assigned on a usage basis, recovered in the sale of each kWh. In this same context, the cost of connecting to the grid may be a customer-specific cost. For items such as groceries and clothing, customers bear

248 Colorado Interstate Gas Co. v. Federal Power Commission, 324 U.S. 581, 589 (1945).

the cost of "connecting to the grid," by traveling to a retailer. The balance of the "grid" cost can and should be recovered in the price of each unit.

As we have noted in this manual, a variety of cost allocation methods are currently in use across the country. There are certain changes in cost allocation methodology that will be specific to the approach appropriate for different regions. However, this manual identifies certain changes in methodology that will be of general application across the continent, including:

- Assigning costs to time periods of usage (such as critical peak, on-peak, midpeak, off-peak and super-off-peak), rather than the much coarser metrics of "demand" and "energy" used in the past.
- Differentiating among types of generation, recognizing that some are relied on during peak periods, while others are relied on during all hours or some other subset of hours during the year.
- Considering that the utilization of some utility assets may have changed. Plants that were built as baseload units may now be operated only intermittently, as newer resources with different cost characteristics become more valuable to the grid.
- Realizing that most utility assets serve shared customer loads, with different customers using these at different times. The application of time-differentiated cost analysis to apportioning the costs of a shared system becomes critical.
- Recognizing that smart grid systems make it possible to provide better service at lower cost by including targeted energy efficiency and demand response measures to meet loads at targeted times and places, and thus that those costs must, to some extent, follow the savings they enable.

Embedded cost of service modeling practices must also be modified to account for new changes in the electric system. Key in this is the need to consider each asset and resource for the purposes for which it was constructed and the functions it provides today. In general, assets that serve in all hours should have their costs assigned to all hours; those that serve only in limited periods, or are upsized at additional cost for certain periods, should have costs assigned to the relevant periods. The traditional methods of defining costs as customer-related, demand-related and energy-related must give way to time-varying purposes, so costs can be fairly assigned among time periods in the new era.

Not surprisingly, marginal cost methods also must change. Although these are used in fewer states than embedded cost methods, they also need significant changes to be relevant in the modern electric industry environment. Methods must be updated to recognize both (1) the substitution of capital costs for short-run variable operating costs and (2) DER solutions for generation, transmission and distribution.

Whether the cost allocation method has changed or not, it is always important to present cost allocation data clearly, so that regulators can do their job. Most regulators expect quality technical analysis of costs but apply judgment in the application of those results. They may want to consider the results of multiple studies using different methods. Gradualism in the implementation of change has important value to avoid sudden impacts that may devastate residential, commercial or industrial customers. Data and analytical results should be presented in a way that informs regulators. We must still recognize, however, that "allocation of costs is not a matter for the slide-rule," as Justice Douglas wrote nearly a century ago.

This manual attempts to define methods that are relevant today and will be applicable into the future as the industry continues to evolve and as technology continues to drive changes in costs, investment and expenses. The reasoned analyst will always need to apply creativity and skill to the task of allocating costs.

# Appendix A: FERC Uniform System of Accounts

Since about 1960, the Federal Energy Regulatory Commission has required electric utilities to follow its Uniform System of Accounts. The system has accounts for both a utility's balance sheet and its income statement.[249]

The balance sheet accounts include 100 to 299, with 300 to 399 providing more detail on utility plant and accounts 430 to 439 providing more detail on retained earnings. Income statement accounts are 400 to 499, excepting 430 to 439. Many of the accounts relevant to utility rate case filings and cost of service studies are identified below.

### 100 to 199: Assets and Other Debits

The asset accounts include plant in service (Account 101) and depreciation reserve (Account 108) — which constitute plant in rate base — and construction work in progress (Account 107), along with a number of smaller accounts.

In most states, not all of these accounts are in rate base,[250] but the ones that typically are include:

- Accounts receivable other than from customers (Account 143).
- Fuel inventories (accounts 120 — nuclear, 151 and 152).
- Emissions allowances inventories (Account 158).
- Materials and supplies inventories (Account 154).
- Prepayments (Account 165, for items such as postage and insurance and in some cases pensions).
- Certain deferred debits (Account 182, especially regulatory assets for which the utility has invested money but not recovered it).
- Deferred tax assets (Account 190, usually netted with accounts 282 and 283).

### 200 to 299: Liabilities and Other Credits

The liability accounts (200 series) have some accounts traditionally in rate base and some not.

The largest elements included as offsets that reduce rate base are accumulated deferred income tax liabilities (accounts 282 and 283). In addition, rate base reductions come from:

- Customer deposits (Account 235, in most but not all states).
- Customer advances for construction (Account 252).[251]
- Deferred credits (regulatory liabilities, in Account 254).
- Unfunded pension liabilities (no specific account).

Elements of the amount of debt and equity, including discounts on issuance and amounts arising from refinancing past debt, are included in the capital structure, while most accounts payable are subsumed in the cash working capital computation.

### 300 to 399: Plant Accounts

The accounts in the 300 series are plant-in-service accounts (providing more detail into utility plant included in Account 101, by type). The accounts are subdivided for electric service[252] into:

Accounts 301 to 303: intangible plant. Today, the costs cover mostly computer software, although there are some

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249 The information here comes from Title 18, Part 101 of the Code of Federal Regulations. Retrieved from https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18. For a useful summary, see Phan, D. (2015, August). *Uniform System of Accounts* [Presentation for NARUC]. Retrieved from https://pubs.naruc.org/pub.cfm?id=53720E26-2354-D714-5100-3EBD02A2034E

250 Most states use a cash working capital calculation that encompasses the utility's accounts receivable and accounts payable for utility service (not always uniformly) so that these items are not in rate base directly but are included in the cash working capital calculation. Arkansas is an exception, so this general discussion does not apply. Arkansas' modified balance sheet approach puts most of the asset items in rate base and most of the liabilities (200-series accounts) in the capital structure as zero-cost capital.

251 Unlike customer advances for construction, contributions in aid of construction do not have a specific place in the Uniform System of Accounts but are simply subtracted from the amount of plant included in summary Account 109 and the detailed accounts 364 to 370.

252 The 300-series accounts used for gas, water and so on are different from the electric accounts.

legacy items for paying for franchises. These costs are usually included with general and common plant as an overhead in cost allocation.

Accounts 310 to 317: steam production plant. These costs include costs of coal, oil and gas steam plants; some utilities include combined cycle steam turbines here. Biomass and geothermal plants owned by utilities would also appear here. Most utilities maintain records of these accounts to the level of the power plant, if not the individual unit of each plant, which are reported in each utility's annual report to FERC (FERC Form 1), although they may be summarized in cost of service studies.

Accounts 320 to 326: nuclear plant. Again, utilities maintain separate records for each nuclear plant or unit, which are presented in FERC Form 1.

Accounts 330 to 337: hydroelectric plant. Utilities generally maintain separate records for each hydro plant, which are also required to be filed as part of FERC Form 1. Pumped storage is included with other hydroelectric plant.

Accounts 340 to 347: other power generation. These include a mix of combustion turbines, combined cycles (as some utilities place entire combined cycles in these accounts), reciprocating engines, and wind and solar generation owned by the utility.

Account 348 is for energy storage plant with a generation function, excluding pumped hydro. This is a new addition to the Uniform System of Accounts and includes batteries, flywheels, compressed air and other storage.

Asset retirement obligations are included in each of the broad categories of production plant (accounts 317, 326 and 347). Asset retirement obligations are not included in rate base and are not directly found in cost of service studies. Aside from nuclear power plants (where they are related to the decommissioning fund), these costs only appear indirectly through the calculation of negative net salvage as part of depreciation.

Accounts 350 to 357: transmission accounts. Costs are divided by type of plant, not by the function or voltage level of plant. Account 351 is a recently added account for energy storage plant used on the transmission system.

Accounts 360 to 374: distribution accounts. Of the major accounts, 362 is distribution substations, 364 is poles, 365 overhead wires, 366 underground conduit, 367 underground wires, 368 line transformers (also including capacitors and voltage regulators), 369 services (sometimes divided into overhead and underground subaccounts), 370 meters, 371 installations on customer premises (usually lighting excluding streetlights but may include demand response equipment) and 373 streetlights. Account 363, used very infrequently now, is the FERC account where energy storage plant installed on the distribution system would be included.

Accounts 382, 383 and 389 to 399: general plant or common plant.

Accounts 382 and 383 are for general plant (largely computer systems) used in regional market operations, particularly for utilities that are members of ISOs.

Accounts 389 to 399 include land, buildings, furniture, computer hardware, vehicles and other similar items. Items at specific power plant sites can be allocated with the plant. Others are part of overhead costs. For an electric and gas utility, some items in these accounts can be "electric general plant" (items used at a power plant site, for example), while others are the portion of "common plant" allocated to the electric department of an electric and gas utility. General plant can also be allocated from a holding company serving a number of utilities.

### 400 to 499: Income and Revenue Accounts

Account 403 (depreciation) and Account 405 (amortization) are subdivided at least by type of plant (different types of production plant, transmission, distribution and general). Many utilities subdivide this further by the FERC plant accounts and by individual power plant or unit.

Account 408 (taxes other than income) is subdivided into accounts for property taxes, payroll taxes and other taxes (usually a small amount).

Current and deferred income taxes are found in accounts 409 and 410 and are usually calculated with significant detail in revenue requirement studies.

The remainder of these accounts do not appear directly in rate cases. Account 426 is noteworthy because it includes nonoperating expenses such as fines and penalties, lobbying, donations and so on. Revenue requirement analysts often try to assess whether costs booked to operating accounts instead belong in this account.

Accounts 433 and 436 to 439 are retained earnings accounts. These accounts, which reflect profits not distributed to shareholders as dividends, do not appear in rate cases.

Accounts 440 to 449 are revenue accounts, using broad customer classes developed by FERC (residential, commercial, industrial, railways, other public authority and sales for resale). These FERC accounts often do not correspond to utility rate classes in a cost allocation study.

Accounts 450 to 456 are revenues that do not come from rates or wholesale transactions. They include late payment charges (Account 450), tariffed service charges (mostly in Account 451), rents (Account 453) and other revenues (Account 456).

### 500 to 599: Production, Transmission and Distribution Expenses

Production expenses are divided similarly to plant and are broken down at the level of individual plants in FERC Form 1.

Steam production operating expenses are in accounts 500 to 509, and maintenance expenses are in accounts 510 to 514.

Nuclear production operating expenses are accounts 517 to 527, and nuclear maintenance expenses are in accounts 528 to 532.

Hydroelectric production expenses are in accounts 535 to 540, and hydro maintenance expenses are in accounts 541 to 545.

Other production plant expenses are in accounts 546 to 550, and other maintenance expenses are in accounts 551 to 554. Again, the definition includes combustion turbines, wind and solar, as above.

Purchased power is in Account 555; production load dispatching is in Account 556; and miscellaneous production expenses (e.g., power procurement administration, renewable energy credits) are in Account 557.

Transmission operating expenses are in accounts 560 to 567; maintenance expenses are in 568 to 573. Of note, wheeling expenses (transmission by others) are in Account 565, and certain expenses paid to ISOs under FERC tariffs are included as subaccounts of Account 561.

Regional market expenses are in accounts 575 (operating) and 576 (maintenance). The bulk of these costs are expenses paid to ISOs under FERC tariff and some internal market monitoring and similar costs.

Distribution operating expenses follow plant and are in accounts 580 to 590. Corresponding maintenance expenses are in accounts 591 to 598.

### 600 to 899: Accounts Reserved for Gas and Water Utilities

Not discussed further.

### 900 to 949: Customer Accounts; Customer Service and Information, Sales, and General and Administrative Expenses

Customer accounting expenses are accounts 901 to 905. Accounts 901 and 905 are generalized expenses, while Account 902 is meter reading. Account 903 is the catchall, including sending bills, collecting money, credit, call centers and similar items. Account 904 is uncollectible accounts expense.

Customer service and information expenses are accounts 907 to 910. Energy efficiency and demand response costs are typically found in Account 908, and Account 909 is instructional advertising.

Sales and marketing expenses are accounts 911 to 916. They include an advertising component in Account 913.

Administrative and general expenses are accounts 920 to 935. There are elements for administrative salaries (920) and nonlabor expenses (921) and contracts (923), as well as insurance (924 and 925), pensions and benefits (926), regulatory commission expenses (928), miscellaneous expenses (930) and rental of buildings and maintenance of general plant (931 to 935). They may include costs from holding companies. Costs in Account 922 are transferred out, either to capital or to other utility affiliates.

In these areas, the FERC Uniform System of Accounts is not particularly uniform. For example, the costs for the same function, such as a key account representative, can appear in accounts 903, 908, 912 or administrative account 920, depending on the utility. Generation procurement expenses, which appear to belong in Account 557, can also end up in the administrative accounts 920 and 921.

# Appendix B: Combustion Turbine Costs Using a Real Economic Carrying Charge Rate[253]

A real economic carrying charge (RECC) rate is designed to measure the economic return expected for an asset whose value increases at the rate of inflation every year. An economic carrying charge also has the property of measuring the value of deferring the construction of an asset from one year to the next.

A levelized nominal-dollar stream of numbers is one way to represent the cost of a power plant. It reflects that if the utility actually bought a combustion turbine today, its costs would be locked in for the 30-year life of the plant. However, using a RECC is more appropriate because it enables the analyst to develop a cost stream for a period shorter than the full life of the plant.[254]

The first step in calculating the RECC begins with calculating the year-by-year revenue requirement of a given asset. One must look at the entire time stream of ownership of an asset and calculate a present value of revenue requirements over the life of the asset using utility accounting. The discount rate used in such a calculation is typically the utility rate of return. (However, there are arguments among analysts as to whether that discount rate is reduced for the tax deductibility of bond interest.[255]) The present value of revenue requirements includes return, depreciation, and income and property taxes and may include certain other costs such as property insurance. From this present value of revenue requirements, one can then calculate the RECC. This is the number of dollars in the first year that, when increased at the rate of inflation every year, results in the same present value at the end of the time period as the present value of revenue requirements.[256]

Figure 47 on the next page is a conceptual example to show the capital and operations and maintenance (O&M) costs for a combustion turbine with a 30-year life. The assumptions used in this example regarding the combustion turbine's capital and O&M costs, as well as capital structure, were developed in a Southwest Public Service Co. case in Texas.[257] The result is that, for this example, the nominal dollar revenue requirement (capital plus O&M) in the first year is $83.54 per kW-year, declining to about $33 per kW-year at the end of the plant's 30-year life as the plant is depreciated. The nominal levelized cost is $63.20. The first-year cost using the RECC is $53.47.

Costs are somewhat sensitive to financial input assumptions. For example, using the capital structure (51% equity and 49% debt) and return on equity (9.3%) offered by the Office of Public Utility Counsel, the first-year RECC in this case would be $52.32. Using Southwest Public Service Co.'s capital structure (58% equity and 42% debt) and return on equity (10.25%), the first-year RECC would be $57.51.

253 This appendix is adapted from Marcus, W. (2018, May). Cross-rebuttal testimony on behalf of the Office of Public Utility Counsel, Appendix A. Public Utility Commission of Texas Docket No. 47527.

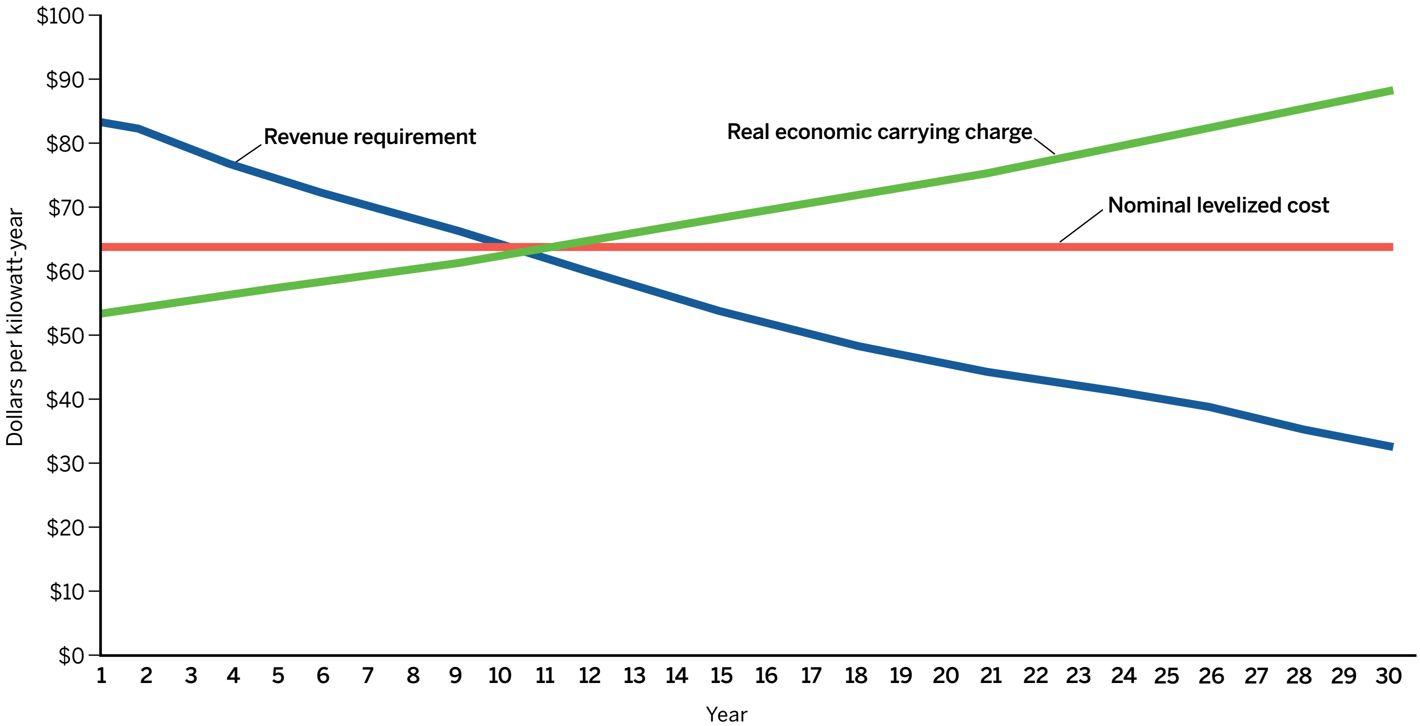
254 Costs calculated based upon time periods shorter than 25 years are considered deferred rather than avoided because combustion plant life cycles are 25 years or greater.

255 Marcus, W. (2013, December). Testimony on behalf of The Utility Reform Network, pp. 2-5. California Public Utilities Commission Application No. 13-04-012.

256 This method of calculating the RECC was developed by National Economic Research Associates (now known as NERA Economic Consulting) in the late 1970s.

257 The case is Public Utility Commission of Texas Docket No. 47527. The capital and O&M costs ($621 per kW and $7.27 per kW-year, respectively) and the inflation rate (1.74%) are from testimony of J. Pollock on behalf of Texas Industrial Energy Consumers (2018, April 25). Property tax rates (0.67%) are those estimated in testimony of N. Koch on behalf of Southwest Public Service Co., Attachment NK-RR-5 (2017, August 21). In addition, the capital structure (48% debt, 52% equity) and return on equity (9.6%) are from the settlement of Southwest Public Service's previous case in Docket No. 45524, with the cost of debt adjusted to the level from Docket No. 47527 (4.38%).

**Figure 47. Comparison of temporal distributions for combustion turbine cost recovery**




Sources: Based on testimony in Public Utility Commission of Texas Docket No. 47527 and settlement of Docket No. 45524 involving Southwest Public Service Co.

# Appendix C: Inconsistent Calculation of Kilowatts in Marginal Cost Studies

Two examples of problematic inconsistencies in measures of demand are identified here to illustrate the problem. Although we have chosen these particular examples, we recognize that additional inconsistencies are likely to be found when analyzing other cost studies.

Pacific Gas & Electric measures demand (except for new hookups, which are measured based on demand at the transformer) using the hottest year in 10 years to develop the marginal cost per kW of regional distribution demand. It thus develops a lower cost per kW than if it used a normal year. The company then multiplies this cost by a peak capacity allocation factor based on a normal year.[258] The peak capacity allocation factor is lower than even the peak demand of the normal year. As a result of the inconsistent measures of demand, its marginal cost revenue requirement of demand is too low relative to its marginal cost revenue requirement of customer costs, inflating the role of customer costs in distribution marginal costs.

Southern California Edison has the same problem, only worse. Its marginal costs are calculated based on system capacity, not demand. System capacity is usually much higher than system demand. As an example, Southern California Edison's subtransmission substation capacity is about 37,000 MWs, even though its time-varying system demand is about 16,000 MWs. The result is that the company obtains a low figure in dollars per kW of capacity (developed using a NERA Economic Consulting regression based on 37,000 MWs of capacity). It then multiplies this figure by 16,000 MWs of time-varying demand. As a result, about 57% of real costs of Edison subtransmission investments disappear in the NERA cost allocation methodology. This mismatch benefits large customers, whose total distribution costs have a larger fraction of subtransmission costs than smaller customers.[259]

258 California Office of Ratepayer Advocates. (2017, February). Testimony, Chapter 4. California Public Utilities Commission Application No. 16-06-013.

259 Marcus, W. (2018, March 23). Testimony on behalf of The Utility Reform Network, pp. 23-28. California Public Utilities Commission Application No. 17-06-030.

# Appendix D: Transmission and Distribution Replacement Costs as Marginal Costs[260]

A competitive business could not continue to operate in the intermediate term if its prices did not recover its costs of doing business. These include the full amount of its O&M costs, plus a return on new capital expenditures (including both capital additions and replacements to the existing system that are necessary to serve the loads of its existing customer base) and investments required to serve new loads and customers. This definition would exclude all sunken capital costs.

To understand this point, an example from another industry might be helpful. Assume that package delivery growth has stagnated in a given area, such that only the same number of packages must be delivered for each of the next 10 years. Then assume that the delivery company (which serves only this area) must replace a portion of its fleet of delivery trucks in order to keep delivering this stable number of packages at some point during this time frame. The NERA method of marginal cost analysis would assume that the replacement trucks are not a marginal cost of serving the demand for packages in this area. As a result, the NERA method assumes that it would be economically inefficient for the trucking company to recover the cost of those replacement trucks (unless a portion of the costs could be recovered in advance at a time when the package demand in the area was growing, prior to the time when truck replacement was actually required), because it would require charging more than the marginal cost of operating the existing trucks.

Moreover, assume that the real cost of trucks increased dramatically in the period between the time the delivery company purchased its original delivery truck fleet and the time it ultimately needs to make replacements of the original fleet (similar to real increases in, for example, the cost of pole replacement and substation transformers due to higher materials costs). Assume also that the price the trucking firm is able to charge its customers has not increased in real terms and the number of packages that its existing customers send and have delivered, on average, has not changed. The question for the delivery company is then: Is the marginal cost of replacing its trucks at least equal to the marginal revenue it will retain by continuing its ability to serve its existing customer base? If not, then the company will not make the replacements, and it will choose to exit the delivery business and employ its capital elsewhere. Just because the decision does not include the possibility of new, additional customers does not mean the delivery company would not make its decision to replace its fleet on the basis of marginal cost and revenue.

The difference between the NERA utility system and the trucking company is largely of degree, not kind: Utility replacements are required less frequently than those of the trucking company and can often be deferred for years; wires must serve a fixed route, whereas the route of a delivery truck may change; and the utility is a monopoly, whereas a trucking company may not be. However, the recovery of the cost of replacements is still part of the long-run marginal cost structure of both companies. Neither could stay in business in a competitive market if each does not recover replacement costs in some way.

In essence, the NERA method's view of this issue is based on the assumption that marginal cost applies only to new demand and not to the retention of existing demand. But this view of marginal cost is not economically correct. First, if the utility does not make required replacements, it will no longer be able to supply load. If it cannot supply load, the quantity

260 This discussion is adapted from Jones, G., and Marcus, W. (2015, March 13). Testimony on behalf of The Utility Reform Network, pp. 23-26. California Public Utilities Commission Application No. 14-06-014.

demanded from the utility will necessarily decline — utility customers will necessarily have to demand their electrons from other sources, such as exclusive distributed generation and storage. Second, marginal cost principles include small changes in costs for small changes in production (not necessarily increases) as a result of changes in demand. Without replacement, and therefore continued service, the utility would not be able to serve the load demanded by existing customers. Were this to occur, the marginal change would be a decline in demand, but it would still be a change in demand, which is what the marginal principles with which we are concerned are to measure in the first place. Finally, a business that cannot continue to serve its existing customers under its cost structure cannot stay in business without losing demand from customers that it can no longer serve economically. Replacement costs (with a few exceptions like undergrounding for policy and aesthetic reasons) are required to assure that loads of existing customers do not decline due to a dilapidated and disintegrating system.

# Appendix E: Undervaluation of Long-Run Avoided Generation Costs in the NERA Method

The theoretical framework of the NERA method to justify the marginal costs based on a combustion turbine for capacity plus projected short-run marginal costs (SRMC) for energy is predicated on the assumption that a utility will add a baseload resource only at the time it will lower average generation costs. Using this fact alone, it can be demonstrated mathematically that SRMC, assuming the existence of the new plant (SRMC1 henceforth), can be below the price that a utility would pay to cost-effectively build a new plant.

The following discussion focuses on the energy cost term. For the cost-effectiveness above to hold, the annual capital cost plus total operating costs of the new plant, less the annual and fixed operating costs of peaking capacity, must be less than the energy costs on the new system avoided by the new plant. Only if these conditions hold would the new plant reduce energy costs.

In the following mathematical demonstration:

- SRMC refers solely to energy costs.
- The cost of a peaker is subtracted from the cost of the new plant.
- SRMC1 is the SRMC with the new plant included.
- The avoided cost from a new plant (ACNP) is the energy cost on the existing system avoided by the new plant.
- SRMC2 is the SRMC without the new plant.
- The new plant cost (NPC) is the total capital plus operating cost of the new plant net of peaker capital and fixed operating costs.

The following inequality must hold:

$$\text{SRMC1} \le \text{ACNP} \le \text{SRMC2}$$

It essentially states that the SRMC curve declines as resources with low fuel costs are added to a utility system that is otherwise the same. In nonmathematical terms, the equation embodies the fact that, for example, the SRMC calculated for a utility system with 100 MWs of must-take wind generation added to the system is below that calculated in the base case without the wind generation.

For the average cost to decline when a new plant is added, a second inequality must also hold:

$$\text{NPC} < \text{ACNP}$$

The new plant must be cheaper than the costs avoided on the existing system by the plant.

Since SRMC1 <= ACNP, a new utility generating station can be cost-effective if its cost is greater than SRMC1, as the following inequality shows:

$$\text{SRMC1} <> \text{NPC} \le \text{ACNP}$$

If SRMC1 > NPC, then the resource is an "inframarginal" resource with costs well below system marginal costs and would be cost-effective at a time of system need for capacity. If the only resources that a utility was building were inframarginal, then SRMC1 represents avoided cost because the utility plant would be cheaper.

If utility plant were infinitely divisible and the utility system were in equilibrium, the special case of a fourth equation would be true:

$$\text{SRMC1} = \text{ACNP} = \text{NPC}$$

In other words, short-run and long-run avoided cost would be equal.

However, if SRMC1 < NPC, then the utility's short-run marginal costs under the NERA method are less than long-run avoided costs. Use of SRMC1 for resource plan evaluation and rate design thus would skew results away from options that may be cheaper than the new plant and would result in allocation and rate design decisions that undervalue energy relative to other components of marginal cost.

# Glossary

**Adjustment clause**
A rate adjustment mechanism implemented on a recurring and ongoing basis to recover changes in expenses or capital expenditures that occur between rate cases. The most common adjustment clause tracks changes in fuel costs and costs of purchased power. Some utilities have weather normalization adjustment clauses that correct for abnormal weather conditions. See also **tracker** and **rider/tariff rider**.

**Administrative and general costs** *Abbreviation:* **A&G**
Capital investments and ongoing expenses that support all of a utility's functions. One example of such a capital investment is an office building that houses employees for the entire utility. An example of such an ongoing expense is the salaries of executives who oversee all parts of the utility.

**Advanced metering infrastructure** *Abbreviation:* **AMI**
The combination of smart meters, communication systems, system control and data acquisition systems, and meter data management systems that together allow for metering of customer energy usage with high temporal granularity; the communication of that information to the utility and, optionally, to the customer; and the potential for direct end-use control in response to real-time cost variations and system reliability conditions. AMI is an integral part of the smart grid concept.

**Allocation/cost allocation**
The assignment of utility costs to customers, customer groups or unbundled services based on cost causation principles.

**Allocation factor/allocator**
A computed percentage for each customer class of the share of a particular cost or group of costs each class is assigned in a cost of service study. Allocation factors are based on data that may include customer count, energy consumption, peak or off-peak capacity, revenue and other metrics.

**Alternating current** *Abbreviation:* **AC**
Current that reverses its flow periodically. Electric utilities generate and distribute AC electricity to residential and business consumers.

**Ampere**
The standard unit of electrical current, formally defined as a quantity of electricity per second. This unit is often used to describe the size of the service connection and service panel for an electricity customer.

**Ancillary service**
One of a set of services offered and demanded by system operators, utilities and, in some cases, customers, generally addressing system reliability and operational requirements. Ancillary services include such items as voltage control and support, reactive power, harmonic control, frequency control, spinning reserves and standby power. The Federal Energy Regulatory Commission defines ancillary services as those services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

**Automated meter reading** *Abbreviation:* **AMR**
Automated meter reading systems use radio or other means to download data from meters periodically without a need for a meter reader to visit each location. They typically do not include interval data of sufficient precision to support advanced services such as critical peak pricing. More sophisticated systems are usually called advanced metering infrastructure.

### Average-and-peak method

A method of apportioning demand-related generation, transmission or distribution costs that assigns a portion of costs equal to the system load factor to all classes based on the kWh usage (average demand) of the class and the balance of costs to each class based on peak demand of each class. The metric for peak demand can be any of those described under **peak responsibility method**.

### Avoided cost

The cost not incurred by not providing an incremental unit of service. Short-run avoided cost is the incremental variable cost to produce another unit from existing facilities. Long-run avoided cost includes the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, environmental costs and line losses associated with delivering that power.

### Base-intermediate-peak method *Abbreviation:* BIP

The base-intermediate-peak cost allocation method assigns each component of generation and often transmission and distribution plant to a category of whether it is fully required in all hours (base) or required only in intermediate or peak hours. It then allocates those costs based on the usage of customer classes in each time period.

### Baseload generation/baseload units/baseload capacity/baseload resources

Electricity generating units that are most economically run for extended hours. Typical baseload units include coal-fired and nuclear-fueled steam generators.

### Basic customer method

A distribution cost allocation approach that classifies only customer-specific costs — such as meters, billing and collection — as customer-related costs, with all other distribution and operating costs assigned based on demand or energy measures of usage.

### Behind the meter

Installations of electrical equipment at customer premises, connected to the building or facility wiring at a point where any impacts are measured by the flow through the customer meter. This may include solar photovoltaic or other generating resources, batteries or other storage, or load control equipment. Behind-the-meter installations are usually owned by the retail customer but may be called upon to provide grid services.

### British thermal unit *Abbreviation:* Btu

A unit of heat, defined as the amount necessary to raise the temperature of 1 pound of water by 1 degree Fahrenheit. Multiples of this unit are frequently used to describe the energy content of fuels.

### Capacity

The ability to generate, transport, process or utilize power. Capacity is measured in watts, usually expressed as kilowatts (1,000 watts), megawatts (1,000 kilowatts) or gigawatts (1,000 megawatts). Generators have rated capacities that describe the output of the generator when operated at its maximum output at a standard ambient air temperature and altitude.

### Capacity factor

The ratio of total energy produced by a generator for a specified period to the maximum it could have produced if it had run at full capacity through the entire period, expressed as a percentage. Fossil-fueled generating units with high capacity factors are generally considered baseload power plants, and those with low capacity factors are generally considered peaking units. These labels do not apply to wind or solar units because the capacity factors for these technologies are driven by weather conditions and not decisions around optimal dispatch.

### Capacity-related costs

See **demand-related costs**.

### Circuit

This generally refers to a wire that conducts electricity from one point to another. At the distribution level, multiple customers may be served by a single circuit that runs from a local substation or transformer to those customers. At the transmission level, the term "circuit" may also describe a pathway along which energy is transported or the number of wires strung along that pathway. See also **conductor**.

### Classification

A step in some cost allocation methods in which costs are defined into categories such as energy-related, demand-related and customer-related.

### Coincident peak *Abbreviation:* CP

The combined demand of a single customer or multiple customers at a specific point in time or circumstance, relative to the peak demand of the system, in which "system" can refer to the aggregate load of a single utility or of multiple utilities in a geographic zone or interconnection or some part thereof.

### Combined cycle unit

A type of generation facility based on combustion that combines a combustion turbine with equipment to capture waste heat to generate additional electricity. This results in more efficient operation (higher output per unit of fuel input).

### Combustion turbine

A power plant that generates electricity by burning oil or natural gas in a jet engine, which spins a shaft to power a generator. Combustion turbines are typically relatively low efficiency, have lower capital costs than other forms of generation and are used primarily as peaking power plants.

### Community choice aggregation

Community choice aggregation involves a municipality or other local entity serving as the electricity purchasing central agent for all customers within a geographic area. The distribution system is still operated by a regulated utility. In some cases, customers can opt out and use another method to obtain electricity supply.

### Competitive proxy method

The usage of information on energy and capacity revenue in competitive wholesale markets in order to classify generation assets for vertically integrated utilities between energy-related and demand-related.

### Conductor

The individual wire or line that carries electricity from one point to another.

### Connection charge

An amount to be paid by a customer to the utility, in a lump sum or installments, for connecting the customer's facilities to the supplier's facilities.

### Contribution in aid of construction

Utilities sometimes require customers to pay a portion of the cost of extending distribution service into sparsely populated areas. These contributions are recorded as a contribution in aid of construction or sometimes as a customer advance that is refundable if additional customers in that area opt for electricity service.

### Cooperative *Abbreviation:* co-op

A not-for-profit utility owned by the customer-members. A co-op is controlled by a member-elected board that includes representatives from business customers.

### Cost allocation

Division of a utility's revenue requirement among its customer classes. Cost allocation is an integral part of a utility's cost of service study.

### Cost of service

Regulators use a cost of service approach to determine a fair price for electric service, by which the aggregate costs for providing each class of service (residential, commercial and industrial) are determined. Prices are set to recover those costs, plus a reasonable return on the invested capital portion of those costs.

### Cost of service study

An analysis performed in the context of a rate case that allocates a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given class represents the costs that class would pay to produce an equal rate of return to other classes. Regulators frequently exercise judgment to adopt rates that vary from study results.

### Critical peak

A limited number of hours every year when the electric system, or a portion of it, is under a significant amount of stress that could cause reliability problems or the need for nontrivial capital investments.

### Critical peak pricing

A form of dynamic retail rate design where a utility applies a substantially higher rate, with advance notice to customers, for a limited number of hours every year when the electric system is projected to be under a significant amount of stress.

### Curtailment

This can refer to different sets of practices for either load or variable renewable generation. With respect to load, curtailment represents a reduction in usage in response to prices and programs or when system reliability is threatened. Price-responsive load curtailment is also known as demand response. Utilities and independent system operators typically have curtailment plans that can be used if system reliability is threatened. Curtailment of variable renewable generation can take place if there is an economic or system reliability reason why the electric system cannot take incremental energy from these units. This could occur when there is more energy available than can be transmitted given delivery constraints, or if the operating constraints of other generators are such that it is more efficient to curtail renewable generation rather than ramp down other units.

### Customer charge

A fixed charge to consumers each billing period, typically to cover metering, meter reading and billing costs that do not vary with size or usage. Also known as a basic service charge or standing charge.

### Customer class

A collection of customers sharing common usage or interconnection characteristics. Customer classes may include residential (sometimes called household), small commercial, large commercial, small industrial, large industrial, agriculture (primarily irrigation pumping), mining and municipal lighting (streetlights and traffic signals). All customers within a class are typically charged the same rates, although some classes may be broken down into subclasses based on the nature of their loads, the capacity of their interconnection (e.g., the size of commercial or residential service panel) or the voltage at which they receive service.

### Customer noncoincident peak demand (or load)

The highest rate of usage in a measurement period of an individual customer — typically in a one-hour, 30-minute or 15-minute interval — unaffected by the usage of other customers sharing the same section of a distribution grid. Also known as maximum customer demand. See also **noncoincident peak**.

### Customer-related costs

Costs that vary directly with the number of customers served by the utility, such as metering and billing expenses.

### Decomposition method

A legacy method that jointly classifies and allocates generation assets. This method assumes that customer classes with high load factors are served by high-capacity-factor baseload resources. In many cases, such a method would advantage the large industrial customer class, although that does depend on the cost of the baseload resources in question. Among other issues, this method ignores reserve requirements or other backup supply needs and any need to equitably share the costs of excess capacity.

### Decoupling

Decoupling fixes the amount of revenue to be collected and allows the price charged to float up or down between rate cases to compensate for variations in sales volume in order to maintain the set revenue level. The target revenue is sometimes allowed to increase between rate cases on the basis of an annual review of costs or a fixed inflator, or on the basis of the number of customers served. The latter approach is sometimes known as revenue-per-customer decoupling. The purpose is to allow utilities to recover allowed costs, independent of sales volumes, without under- or overcollection over time. Also known as revenue regulation.

### Default service/default supply

In a restructured electric utility, the power supply price a customer will pay if a different supplier than the distribution utility is not affirmatively chosen. Most residential and small-business consumers are served by the default supply option in areas where it is available. Also known as standard service offer or basic service.

### Demand

In theory, an instantaneous measurement of the rate at which electricity is being consumed by a single customer or customer class or the entirety of an electric system, expressed in kilowatts or megawatts. Demand is the load-side counterpart to an electric system's capacity. In practical terms, electricity demand is actually measured as the average rate of energy consumption over a short period, usually 15 minutes or an hour. For example, a 1,000-watt hair dryer run for the entirety of a 15-minute demand interval would cause a demand meter using a 15-minute demand interval to record 1 kilowatt of demand. If that same hair dryer were run for only 7.5 minutes, however, the metered demand would be only 0.5 kilowatt. Not all electric meters measure demand.

### Demand charge

A charge paid on the basis of metered demand typically for the highest hour or 15-minute interval during a billing period. Demand charges are usually expressed in dollars per watt units, such as kilowatts. Demand charges are common for large (and sometimes small) commercial and industrial customers but have not typically been used for residential customers because of the very high diversity among individual customers' usage and the higher cost of demand meters or interval meters. The widespread deployment of smart meters would enable the use of demand charges or time-of-use rates for any customer served by those meters.

### Demand meter

A meter capable of measuring and recording a customer's demand. Demand meters include interval meters and smart meters.

### Demand-related costs/capacity-related costs

Costs that vary directly with the system capacity to meet peak demands. This can be measured separately for the generation, transmission and distribution segments of the utility system.

### Demand response

Reduction in energy use in response to either system reliability concerns or increased prices (where wholesale markets are involved) or generation costs (in the case of vertically integrated utilities). Demand response generally must be measurable and controllable to participate in wholesale markets or be relied upon by system operators.

### Depreciation

The loss of value of assets, such as buildings and transmission lines, owing to age and wear.

### Direct current *Abbreviation:* DC

An electric current that flows in one direction, with a magnitude that does not vary or that varies only slightly.

### Distributed energy resource *Abbreviation:* DER

Any resource or activity at or near customer loads that generates energy, reduces consumption or otherwise manages energy on-site. Distributed energy resources include customer-site generation, such as solar photovoltaic systems and emergency backup generators, as well as energy efficiency, controllable loads and energy storage.

### Distributed generation

Any electricity generator located at or near customer loads. Distributed generation usually refers to customer-sited generation, such as solar photovoltaic systems, but may include utility-owned generation or independent power producers interconnected to the distribution system.

### Distribution

The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and lower).

### Distribution utility

A utility that owns and operates only the distribution system. It may provide bundled service to customers by purchasing all needed energy from one or more other suppliers or may require that customers make separate arrangements for energy supply. See also **vertically integrated utility**.

### Distribution system

That portion of the electric system used to distribute energy to customers. The distribution system is usually distinguished from the transmission system on the basis of voltage and function. Components operating above 100 kV are considered transmission. Components operating below 50 kV are considered distribution. Facilities between 50 kV and 100 kV are often termed subtransmission but are normally included in the distribution service FERC accounts. After energy is received from a large generating facility, its voltage is stepped up to very high levels where it is transported by the transmission system. Power from distributed generating facilities such as small photovoltaic systems is normally delivered into the distribution system and transported to nearby customers at the distribution system level without ever entering the transmission system.

### Distribution system operator

The entity that operates the distribution portion of an electric system. In the case of a vertically integrated utility, this entity would also provide generation and transmission services. In many restructured markets, the distribution system operator provides only delivery services and may provide only limited energy services as a provider of last resort.

### Diversity/customer diversity/load diversity

The measurement of how different customers use power at different times of the day or year, and the extent to which those differences can enable sharing of system generation, transmission or distribution capacity. For example, schools use power primarily during the day, and street lighting uses power exclusively during hours of darkness; they are able to share system capacity. By contrast, continuous-use customers, such as data centers and all-night mini-marts, preempt the use of capacity. Irrigators use power in summer, and space heat uses power in winter, also allowing the seasonal sharing of generation but sometimes not of distribution capacity.

### Dynamic pricing

Rates that may be adjusted frequently, such as hourly or every 15 minutes, based on wholesale electricity costs or actual generation costs. Also known as real-time pricing. See also **critical peak pricing**.

### Embedded cost of service study

A cost allocation study that apportions the actual historic test year or projected future rate year system costs among customer classes, typically using customer usage patterns in a single yearlong period to divide up the costs. Sometimes called a fully allocated cost of service study. See also **marginal cost of service study** and **total service long-run incremental cost**.

### Embedded costs

The actual current costs, including a return on existing plant, used to provide service. These are reflected in the FERC system of accounts reported in each utility's FERC Form 1 filing. See also **marginal costs**.

### Energy

A unit of power consumed over a period of time. Energy is expressed in watt-time units, in which the time units are usually one hour, such as a kilowatt-hour, megawatt-hour and so on. An appliance placing 1 kilowatt of demand on the system for an hour will consume 1 kilowatt-hour of energy. See also **watt** and **watt-hour**.

**Energy charge**
A price component based on energy consumed. Energy charges are typically expressed in cents per kilowatt-hour and may vary based on the time of consumption.

**Energy efficiency**
The deployment of end-use appliances that achieve the same or greater end-use value while reducing the energy required to achieve that result. Higher-efficiency boilers and air conditioners, increased building insulation, more efficient lighting and higher energy-rated windows are all examples of energy efficiency. Energy efficiency implies a semipermanent, longer-term reduction in the use of energy by the customer, contrasted with behavioral programs that may influence short-term usage habits. Because energy efficiency reduces the need for generation, transmission and distribution, these costs are properly allocated using the methods applied to all three functions.

**Energy-related costs**
Costs that vary directly with the number of kilowatt-hours the utility provides over a period of time.

**Equal percentage of marginal cost** *Abbreviation:* **EPMC**
A method of adjusting the results of a marginal cost of service study to the system revenue requirement by adjusting the cost responsibility of each class by a uniform percentage. Often applied within the functional categories of generation, transmission and distribution.

**Equivalent forced outage rate**
The percentage of the hypothetical maximum output of a generating unit during a year that is unavailable due to unplanned outages, either full or partial, of the unit.

**Equivalent peaker method**
A method of classifying production and transmission costs that assigns a portion of investment and maintenance costs as demand-related — based on the cost of a peaking resource such as demand response or a peaking power unit that can be deployed within the service territory — and the balance of costs as energy-related. Commonly used for nuclear, coal and hydroelectric resources and associated transmission.
Also known as the peak credit method.

**Externalities**
Costs or benefits that are side effects of economic activities and are not reflected in the booked costs of the utility. Environmental impacts are the principal externalities caused by utilities (e.g., climate impacts or health care costs from air pollution).

**Extra-high voltage** *Abbreviation:* **EHV**
Transmission lines operating at 765 kV (alternating current) or roughly 400 kV (direct current) or above.

**Federal Energy Regulatory Commission**
*Acronym:* **FERC**
The U.S. agency that has jurisdiction over interstate transmission systems and wholesale sales of electricity.

**Fixed charge**
Any fee or charge that does not vary with consumption. Customer charges are a typical form of fixed charge. In some jurisdictions, customers are charged a connected load charge that is based on the size of their service panel or total expected maximum load. Minimum bills and straight fixed/variable rates are additional forms of fixed charges.

**Fixed cost**
This accounting term is meant to denote costs that do not vary within a certain period of time, usually one year, primarily interest expense and depreciation expense. This term is often misapplied to denote costs associated with plant and equipment (which are themselves denoted as fixed assets in accounting terms) or other utility costs that cannot be changed in the short term. From a regulatory and economics perspective, the concept of fixed costs is irrelevant. For purposes of regulation, all utility costs are variable in the long run. Even the costs associated with seemingly fixed assets, such as the distribution system, are not fixed, even in the short run. Utilities are constantly upgrading and replacing distribution

facilities throughout their systems as more customers are served and customer usage increases, and efforts to reduce demand can have immediate impacts on those costs.

**Flat volumetric rate**
A rate design with a uniform price per kilowatt-hour for all levels of consumption.

**Fuel adjustment clause**
An adjustment mechanism that allows utilities to recover all or part of the variation in the cost of fuel or purchased power from the levels assumed in a general rate case. See also **adjustment clause**.

**Fuel cost**
The cost of fuel, typically burned, used to create electricity. Types include nuclear, coal, natural gas, diesel, biomass, bagasse, wood and fuel oil. Some generators, such as wind turbines and solar photovoltaic and solar thermal generators, use no fuel or, in the case of hydroelectric generation, virtually cost-free fuel.

**Functionalization**
A step in most cost allocation methods in which costs are defined into functional categories, such as generation-related, transmission-related, distribution-related, or administrative and general costs.

**General service**
A term broadly applied to nonresidential customers. It sometimes includes industrial customers and sometimes is distinct from an industrial class. It is often divided into small, medium and large by maximum demand or into secondary and primary by voltage.

**Generation**
Any equipment or device that supplies energy to the electric system. Generation is often classified by fuel source (i.e., nuclear, coal, gas, solar and so on) or by operational or economic characteristics (e.g., "must-run," baseload, intermediate, peaking, intermittent, load following).

**Grid**
The electric system as a whole or the nongeneration portion of the electric system.

**Heat rate**
The number of British thermal units that a thermal power plant requires in fuel to produce 1 kilowatt-hour.

**Highest 100 (or 200) hours method**
A method for allocating demand-related or capacity-related costs that considers class demand over the highest 100 (or 200) hours of usage during the year.

**High-voltage direct current** *Abbreviation:* **HVDC**
An HVDC electric power transmission system uses direct current for the bulk transmission of electrical power, in contrast to the more common alternating current systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses.

**Hourly allocation**
An allocation approach in which costs or groups of costs are assigned to hourly time periods rather than classified between demand- and energy-related costs.

**Incremental cost**
The short-run cost of augmenting an existing system. An incremental cost study rests on the theory that prices should reflect the cost of producing the next unit of energy or deployment of the next unit of capacity in the form of generation, transmission or distribution. See also **long-run marginal costs**, **short-run marginal costs** and **total system long-run incremental cost**.

**Independent power producer**
A power plant that is owned by an entity other than an electric utility. May also be referred to as a non-utility generator.

**Independent system operator** *Abbreviation:* **ISO**
A non-utility entity that has multi-utility or regional responsibility for ensuring an orderly wholesale power market, the management of transmission lines and the dispatch of power resources to meet utility and non-utility needs. All existing ISOs also act as regional transmission organizations, which control and operate the transmission system independently of the local utilities that serve customers. This usually includes control of the dispatch of generating units and calls on demand response resources over the course of a day or year. In regions without an ISO, less formal entities and markets exist for wholesale trading and regional transmission planning. See also **regional transmission organization**.

**Intermediate unit**
A generic term for units that operate a substantial portion of the year but not at all times or just hours near peaks or with reliability issues. As a result, these units can be described as neither baseload nor peaking. Over the past two decades, this role has been filled by natural gas combined cycle units in many places. Intermediate units are also known as midmerit or cycling units.

**Intermittent resources**
See **variable resources**.

**Interruptible rate/interruptible customer**
An interruptible rate is a retail service tariff in which, in exchange for a fee or a discounted retail rate, the customer agrees to curtail service when called upon to do so by the entity offering the tariff, which may be the local utility or a third-party curtailment service provider. A customer's service may be interrupted for economic or reliability purposes, depending on the terms of the tariff. Customers on these rates are sometimes described as interruptible customers, and it is said that they receive interruptible service.

**Interval meter**
A meter capable of measuring and recording a customer's detailed consumption data. An interval meter measures demand by recording the energy used over a specified interval of time, usually 15 minutes or an hour.

**Inverse elasticity rule**
A method of reconciling the marginal cost revenue requirement with the embedded cost revenue requirement. In principle, the adjustment of the least-elastic element of costs (and thus the underlying rates) produces a less distortive and more optimal outcome for customer behavior. The inverse elasticity rule follows this principle by adjusting the least-elastic element upward if there is a shortfall or downward if there is a surplus. There are numerous theoretical and practical difficulties in determining which element of costs or rates is least elastic.

**Investor-owned utility** *Abbreviation:* **IOU**
A utility owned by shareholders or other for-profit owners. A majority of U.S. electricity consumers are served by IOUs.

**Kilovolt** *Abbreviation:* **kV**
A kilovolt is equal to 1,000 volts. This unit is the typical measure of electric potential used to label transmission and primary distribution lines.

**Kilovolt-ampere** *Abbreviation:* **kVA**
A kilovolt-ampere is equal to 1,000 volt-amperes. This unit is the typical measure for the capacity of line transformers.

**Kilowatt** *Abbreviation:* **kW**
A kilowatt is equal to 1,000 watts.

**Kilowatt-hour** *Abbreviation:* **kWh**
A kilowatt-hour is equal to 1,000 watt-hours.

**Line transformer**
A transformer directly providing service to a customer, either on a dedicated basis or among a small number of customers. A line transformer typically is stepping down power on a distribution line from primary voltage to secondary voltage that consumers can use directly.

**Load**
The combined demand for electricity placed on the system. The term is sometimes used in a generalized sense to simply denote the aggregate of customer energy usage on the system,

or in a more specific sense to denote the customer demand at a specific point in time.

**Load factor**

The ratio of average load of a customer, customer class or system to peak load during a specific period of time, expressed as a percentage.

**Load following**

The process of matching variations in load over time by increasing or decreasing generation supply or, conversely, decreasing or increasing loads. One or more generating units or demand response resources will be designated as the load following resources at any given time. Baseload and intermediate generation is generally excluded from this category except in extraordinary circumstances.

**Load shape**

The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

**Long-run marginal costs/long-run incremental costs**

The costs of expanding or maintaining the level of utility service, including the cost of a new or replacement power plants, transmission and distribution, reserves, marginal losses, and administrative and environmental costs, measured over a period of years in which new investment is expected to be needed.

**Losses/energy losses/line losses**

The energy (kilowatt-hours) and power (kilowatts) lost or unaccounted for in the operation of an electric system. Losses are usually in the form of energy lost to heat, sometimes referred to as technical losses; energy theft from illegal connections or tampered meters is sometimes referred to as nontechnical losses.

**Loss-of-energy expectation**

A mathematical study of a utility system, applying expected availability of multiple generating resources, that estimates the expected energy loss at each hour of the year when power supply and demand response resources are insufficient to meet customer demand. Related terms: loss-of-load probability, loss-of-load hours, loss-of-load expectation, probability of peak and expected unserved energy.

**Loss-of-energy expectation method**

A method for allocating demand-related costs in a manner that is weighted over all of the hours with reliability risks.

**Marginal cost of service study**

A cost allocation study that apportions costs among customer classes using estimates of how costs change over time in response to changes in customer usage. See also **embedded cost of service study** and **total service long-run incremental cost.**

**Marginal costs**

The cost of augmenting output. Short-run marginal costs are the incremental expenses associated with increasing output with existing facilities. Long-run marginal costs are the incremental capital and operating expenses associated with increasing output over time with an optimal mix of assets. Total system long-run incremental costs are the costs of building a new system in its entirety, a measure used to determine if an existing utility system is economical.

**Marginal cost revenue requirement** *Abbreviation:* **MCRR**

An output in a marginal cost of service study, where the marginal unit costs for each element of the electric system are multiplied by the billing determinants for each class to produce a class marginal cost revenue requirement for each element. These can be aggregated to produce a system MCRR. It is only happenstance if the system MCRR equals the embedded cost revenue requirement, so the elements of the MCRR can be used in different ways to allocate embedded costs among the customer classes. See also **reconciliation**.

**Megawatt** *Abbreviation:* **MW**
A megawatt is equal to 1 million watts or 1,000 kilowatts.

**Megawatt-hour** *Abbreviation:* **MWh**
A megawatt-hour is equal to 1 million watt-hours or 1,000 kilowatt-hours.

**Megawatt-year**
A megawatt-year is the amount of energy that would equal 1 megawatt continuously for one year, or 8.76 million kilowatt-hours. Also known as an average megawatt.

**Meter data management system**
A computer and control system that gathers metering information from smart meters and makes it available to the utility and, optionally, to the customer. A meter data management system is part of the suite of smart technologies and is integral to the smart grid concept.

**Midpeak**
Hours that are between on-peak hours and off-peak hours. These are typically the hours when intermediate power plants are operating but peaking units are not. Used primarily in the base-intermediate-peak cost allocation method and in time-of-use rate design.

**Minimum system method**
A method for classifying distribution system costs between customer-related and demand- or energy-related. It estimates the cost of building a hypothetical system using the minimum size components available as the customer-related costs and the balance of costs as demand-related or energy-related.

**Municipal utility** *Abbreviation:* **muni**
A utility owned by a unit of government and operated under the control of a publicly elected body.

**National Association of Regulatory Utility Commissioners** *Acronym:* **NARUC**
The association of state and federal regulatory agencies that determine electric utility tariffs and service standards. It includes the state, territorial and federal commissions that regulate utilities and some transportation services.

**NERA method**
An approach to measuring marginal costs for electric utilities that considers a mix of time frames. It looks at customer-related costs such as metering on a full replacement or new install basis and at transmission or distribution capacity costs over a time frame of 10 years or more to include at least some capacity upgrades. Generation costs consider the new install costs for peaking capacity and a dispatch model approach to variable energy costs. The NERA method has formed the foundation for the methods used in several states today, but each state has modified the approach. This approach is named after the firm that developed it in the 1970s, National Economic Research Associates (now NERA Economic Consulting).

**New-customer-only method** *Abbreviation:* **NCO**
A short-run method for estimation of marginal customer connection costs based on the cost of hookups for new customers. This method may or may not include the percentage of existing hookups that are replaced every year. See also **rental method**.

**Noncoincident peak** *Abbreviation:* **NCP**
The maximum demand of a customer, group of customers, customer class, distribution circuit or other portion of a utility system, independent of when the maximum demand for the entire system occurs.

**Off-peak**
The period of time that is not on-peak. During off-peak periods, system costs are generally lower and system reliability is not an issue, and only generating units with lower short-run variable costs are operating. This may include high-load hours if nondispatchable generation, such as solar photovoltaic energy, is significant within the service area. Time-of-use rates typically have off-peak prices that are lower than on-peak prices.

### On-peak

The period of time when storage units and generating units with higher short-run variable costs are operating to supply energy or when transmission or distribution system congestion is present. During on-peak periods, system costs are higher than average and reliability issues may be present. Many rate designs and utility programs are oriented to reducing on-peak usage. Planning and investment decisions are often driven by expectations about the timing and magnitude of peak demand during the on-peak period. Time-of-use rates typically have on-peak prices that are higher than off-peak prices.

### Operational characteristics method

The traditional version of this method uses the capacity factor of a resource to determine the energy-related percentage of the costs of a generation asset and designates the remainder as demand-related. Although this provides a reasonable result in some circumstances, it inaccurately increases the demand-related percentage for less-reliable resources. A variation on this approach is to use the operating factor — the ratio of output to the equivalent availability of the unit — as the energy-related percentage.

### Operations and maintenance costs *Abbreviation:* O&M

All costs associated with operating, maintaining and supporting the utility plant, including labor, outside services, administrative costs and supplies. For generation facilities, this includes O&M expenses that vary directly with the output of the facility (dispatch O&M), such as fuel and water treatment, and expenses that do not vary with output but are incurred yearly or monthly (nondispatch O&M).

### Peak capacity allocation factor *Acronym:* PCAF

An allocation factor where a weighted portion of demand-related costs is assigned to every hour in excess of 80% of peak demand. This method, used in California, is weighted such that the peak hour has an allocation that is 20 times the allocation for the hours at 81% of peak demand and twice the allocation of an hour at 90% of peak demand.

### Peak demand

The maximum demand by a single customer, a group of customers located on a particular portion of the electric system, all of the customers in a class or all of a utility's customers during a specific period of time — hour, day, month, season or year.

### Peaking resources/peaking generation/peakers

Generation that is used to serve load during periods of high demand. Peaking generation typically has high fuel costs or limited availability (e.g., storage of hydrogeneration) and often has low capital costs. Peaking generation is used for a limited number of hours, especially as compared with baseload generation. Peaking resources often include nongeneration resources, such as storage or demand response.

### Peak load

The maximum total demand on a utility system during a period of time.

### Peak responsibility method

A method of apportioning demand-related generation or transmission costs based on the customer class share of maximum demand on the system. The metric can be a single hour (1 CP), the highest hour in several months (such as 4 CP), the highest hour in every month (12 CP) or the entire group of highest peak hours (such as 200 CP). See also **coincident peak**.

### Performance-based regulation *Abbreviation:* PBR

An approach to determining the utility revenue requirement that departs from the classical formula of rate base, rate of return, and operation and maintenance expense. It is designed to encourage improved performance by utilities on cost control or other regulatory goals.

### Postage stamp pricing

The practice of having separate sets of prices for a relatively small and easily identifiable number of customer classes. Every customer in a given customer class generally pays the same prices regardless of location in a utility's service territory, although separate prices may exist for subclasses in some cases.

**Power factor**
The fraction of power actually used by a customer's electrical equipment compared with the total apparent power supplied, usually expressed as a percentage. A power factor indicates the extent to which a customer's electrical equipment causes the electric current delivered at the customer's site to be out of phase with system voltage.

**Power quality**
The power industry has established nominal target operating criteria for a variety of properties associated with the power flowing over the electric grid. These include frequency, voltage, power factor and harmonics. Power quality describes the degree to which the system, at any given point, is able to exhibit the target operating criteria.

**Primary voltage/primary service**
Primary voltage normally includes voltages between 2 kV and 34 kV. Primary voltage facilities generally are considered part of the distribution system.

**Probability-of-dispatch method** *Abbreviation:* **POD**
A cost allocation methodology that considers the likelihood that specific generating units and transmission lines will be needed to provide service at specific periods during the year and assigns costs to each period based on those probabilities.

**Public utilities commission/public service commission**
The state regulatory body that determines rates for regulated utilities. Although they go by various titles, these two are the most common.

**Public Utilities Regulatory Policy Act**
*Acronym:* **PURPA**
This federal law, enacted in 1978 and amended several times, contains two essential elements. The first requires state regulators to consider and determine whether specific rate-making policies should be adopted, including whether rates should be based on the cost of service. The second requires utilities to purchase power at avoided-cost prices from independent power producers.

**Rate base**
The net investment of a utility in property that is used to serve the public. This includes the original cost net of depreciation, adjusted by working capital, deferred taxes and various regulatory assets. The term is often misused to describe the utility revenue requirement.

**Rate case**
A proceeding, usually before a regulatory commission, involving the rates, revenues and policies of a public utility.

**Rate design**
Specification of prices for each component of a rate schedule for each class of customers, which are calculated to produce the revenue requirement allocated to the class. In simple terms, prices are equal to revenues divided by billing units, based on historical or assumed usage levels. Total costs are allocated across the different price components such as customer charges, energy charges and demand charges, and each price component is then set at the level required to generate sufficient revenues to cover those costs.

**Rate of return**
The weighted average cost of utility capital, including the cost of debt and equity, used as one of the three core elements of determining the utility revenue requirement and cost of service, along with rate base and operating expense.

**Rate year**
The period for which rates are calculated in a utility rate case, usually the 12-month period immediately following the expected effective date of new rates at the end of the proceeding.

**Real economic carrying charge** *Acronym:* **RECC**
An annualized cost expressed in percentage terms that reflects the annual "mortgage" payment that would be required to pay off a capital investment at the utility's real (net of inflation) cost of capital over its expected lifetime. It is used in long-run marginal cost and total system long-run incremental cost studies.

**Reconciliation/revenue reconciliation/ cost reconciliation**

In a marginal cost of service study, it is only happenstance if the system marginal cost revenue requirement is equal to the embedded cost revenue requirement that needs to be recovered by the utility to earn a fair return. As a result, the marginal cost revenue requirement must be reconciled to the embedded cost revenue requirement. There are two primary methods for this: equal percentage of marginal cost and the inverse elasticity rule. See also **marginal cost revenue requirement**.

**Regional Greenhouse Gas Initiative**

An agreement among Northeast and mid-Atlantic states to limit the amount of greenhouse gases emitted in the electric power sector and to price emissions by auctioning emissions allowances.

**Regional transmission organization** *Abbreviation:* **RTO**

An independent regional transmission operator and service provider established by FERC or that meets FERC's RTO criteria, including those related to independence and market size. RTOs control and manage the high-voltage flow of electricity over an area generally larger than the typical power company's service territory. Most also serve as independent system operators, operating day-ahead, real-time, ancillary services and capacity markets, and conduct system planning. See also **independent system operator**.

**Renewable portfolio standard** *Abbreviation:* **RPS**

A requirement established by a state legislature or regulator that each electric utility subject to its jurisdiction obtain a specified portion of its electricity from a specified set of resources, usually renewable energy resources but sometimes including energy efficiency, nuclear energy or other categories.

**Rental method**

A method of estimating marginal customer connection costs where the cost of new customer connection equipment is multiplied by the real economic carrying charge to obtain an estimate of a rental price. This is a long-run method for customer connection costs that has been a part of the NERA method for marginal costs. See also **new-customer-only method**.

**Reserves/reserve capacity/reserve margin**

The amount of capacity that a system must be able to supply, beyond what is required to meet demand, to assure reliability when one or more generating units or transmission lines are out of service. Traditionally a 15% to 20% reserve capacity was thought to be needed for good reliability. In recent years, due to improved system controls and data acquisition, the accepted value in some areas has declined to 10% or lower.

**Restructured state/restructured utility/ restructured market**

Replacement of the traditional vertically integrated utility with some form of competitive market. In some cases, the generation and transmission components of service are purchased by the customer-serving distribution utility in a wholesale competitive market. In other cases, retail customers are allowed to choose their generation suppliers directly in a competitive market.

**Retail competition/retail choice**

A restructured market in which customers are allowed to or must choose their own competitive supplier of generation and transmission services. In most states with retail choice, the incumbent utility or some other identified entity is designated as a default service provider for customers who do not choose another supplier. In Texas, there is no default service provider and all customers must choose a retail supplier.

**Revenue requirement**

The annual revenues that the utility is entitled to collect (as modified by adjustment clauses). It is the sum of operations and maintenance expenses, depreciation, taxes and a return on rate base. In most contexts, "revenue requirement" and "cost of service" are synonymous.

### Rider/tariff rider

A special tariff provision that collects a specified cost or refunds a specific consumer credit, usually over a limited period. See also **adjustment clause** and **tracker**.

### Secondary voltage/secondary service

Secondary voltage normally includes only voltages under 600 volts. Secondary voltage facilities generally are considered part of the distribution system.

### Service line/service drop

The conductor directly connecting an electricity customer to the grid, typically between the meter and the line transformer. The term "service drop" derives from the fact that in many cases this line literally drops down from shared transformers attached to overhead lines, but today many are underground.

### Short-run marginal costs/short-run incremental costs

The costs incurred immediately to expand production and delivery of utility service, not including any capital investments. They are usually much lower than the average of costs but may be higher than average costs during periods of system stress or deficiency of capacity.

### Site infrastructure

The utility investment that is located at the customer premises and serves no other customers than those located at a single point of delivery from the distribution system. Site infrastructure costs are either paid by the customer at the time of service connection or else classified as customer-related costs in cost of service studies.

### Smart grid

An integrated network of sophisticated meters, computer controls, information exchange, automation, information processing, data management and pricing options that can create opportunities for improved reliability, increased consumer control over energy costs and more efficient utilization of utility generation and transmission resources.

### Smart meter

An electric meter with electronics that enable recording of customer usage in short time intervals and two-way communication of data between the utility, the meter and optionally the customer.

### Spinning reserve

Any energy resource or decremental load that can be called upon within a designated period of time and that system operators may use to balance loads and resources. Spinning reserves may be in the form of generators, energy storage or demand response. Spinning reserves may be designated by how quickly they can be made available, from instantaneously up to some short period of time. In the past, this meant actual rotating (spinning) power plant shafts, but today "spinning" reserves can be provided by battery storage, flywheels or customer load curtailment.

### Straight fixed/variable

A rate design method that designate much or all of the distribution system as a fixed cost and places all of those costs on customers through customer charges. There are related cost allocation approaches, which designate the entire distribution system as a customer-related cost and transmission and generation capacity as entirely demand-related. See also **minimum system method** and **basic customer method**.

### Stranded costs

Utility costs for plant that is no longer used or no longer economic. This may include fossil-fueled power plants made uneconomic by new generating technologies; assets that fail to perform before they are fully depreciated; or distribution facilities built to serve customers who are no longer taking utility service, such as failed industrial sites and customers choosing self-generation as a replacement for utility service. Some regulators allow recovery of stranded costs from continuing customers and the inclusion of these costs in the cost of service methodology.

### Substation

A facility with a transformer that steps voltage down from transmission or subtransmission voltage to distribution voltage, to which one or more circuits or customers may be connected.

### System load factor

The ratio of the average load of the system to peak load during a specific period of time, expressed as a percentage.

### System peak demand

The maximum demand placed on the electric system at a single point in time. System peak demand may be a measure for an entire interconnection, for subregions within an interconnection or for individual utilities or service areas.

### Tariff

A listing of the rates, charges and other terms of service for a utility customer class, as approved by the regulator.

### Test year

A specific period chosen to demonstrate a utility's need for a rate increase or decrease. It may include adjustments to reflect known and measurable changes in operating revenues, expenses and rate base. A test year can be either historical or projected (often called "future" or "forecast" test year).

### Time-of-use rates/time-varying rates *Abbreviation:* TOU

Rates that vary by time of day and day of the week. TOU rates are intended to reflect differences in underlying costs incurred to provide service at different times of the day or week. They may include all costs or reflect only time differentiation in a component of costs such as energy charges or demand charges.

### Total service long-run incremental cost *Abbreviation:* TSLRIC

The cost of replicating the current utility system with new power supply, transmission and distribution resources, using current technology, and optimizing the system for current service needs. Used as a metric for the cost that a new competitive entrant would incur to provide utility services, as an indicator of the equitability of current class cost allocations and rate designs.

### Tracker

A rate schedule provision giving the utility company the ability to change its rates at different points in time to recognize changes in specific costs of service items without the usual suspension period of a rate filing. Costs included in a tracker are sometimes excluded from cost of service studies. See also **adjustment clause** and **rider/tariff rider**.

### Transformer

A device that raises (steps up) or lowers (steps down) the voltage in an electric system. Electricity coming out of a generator is often stepped up to very high voltages (230 kW or higher) for injection into the transmission system and then repeatedly stepped down to lower voltages as the distribution system fans out to connect to end-use customers. Some energy loss occurs with every voltage change. Generally, higher voltages can transport energy for longer distances with lower energy losses.

### Transmission/transmission system

That portion of the electric system designed to carry energy in bulk, typically at voltages above 100 kV. The transmission system is operated at the highest voltage of any portion of the system. It is usually designed to either connect remote generation to local distribution facilities or to interconnect two or more utility systems to facilitate exchanges of energy between systems.

### Transmission and distribution *Abbreviation:* T&D

The combination of transmission service and equipment and distribution service and equipment.

### Used and useful

A determination on whether investment in utility infrastructure may be recovered in rate base, such that new rates will enable the utility to recover those costs in the future when that plant will be providing service (i.e., when it will be used and useful). In general, "used" means that the facility is actually providing service, and "useful" means that, without the facility, either costs would be higher or the quality of service would be lower.

**Variable resources/variable renewable resources/ intermittent resources**
Technologies that generate electricity under the right conditions, such as when the sun is shining for solar.

**Vertically integrated utility**
A utility that owns its own generating plants (or procures power to serve all customers), transmission system and distribution lines, providing all aspects of electric service.

**Volt** *Abbreviation:* **V**
The standard unit of potential difference and electromotive force, formally defined to be the difference of electric potential between two points of a conductor carrying a constant current of 1 ampere, when the power dissipated between these points is equal to 1 watt. A kilovolt is equal to 1,000 volts. In abbreviations, the V is capitalized in recognition of electrical pioneer Alessandro Volta.

**Volt-ampere**
A unit used for apparent power in an alternating current electrical circuit, which includes both real power and reactive power. This unit is equivalent to a watt but is particularly relevant in circumstances where voltage and current are out of phase, meaning there is a non-zero amount of reactive power. This unit and its derivatives (e.g., kilovolt-ampere) are typically used for line transformers.

**Volt-ampere reactive** *Acronym:* **VAR**
A unit by which reactive power is expressed in an alternating current electric power system. Reactive power exists in an alternating current circuit when the current and voltage are not in phase.

**Volumetric energy charges/volumetric rate**
A rate or charge for a commodity or service calculated on the basis of the amount or volume the purchaser receives.

**Watt**
The electric unit used to measure power, capacity or demand. A kilowatt equals 1,000 watts; a megawatt equals 1 million watts or 1,000 kilowatts.

**Watt-hour**
The amount of energy generated or consumed with 1 watt of power over the course of an hour. One kilowatt-hour equals 1,000 watts consumed or delivered for one hour. One megawatt-hour equals 1,000 kilowatt-hours. One terawatt-hour equals 1,000 megawatt-hours. In abbreviations, the W is capitalized in recognition of electrical pioneer James Watt.

**Zero-intercept approach/zero-intercept method**
A method for classifying distribution system costs between customer-related and demand- or energy-related that uses a cost regression calculation to compare components of different size actually used in a system to estimate the costs of a hypothetical zero-capacity distribution system.

# PUBLIC STAFF
# NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-100, Sub 162

Before the North Carolina Utilities Commission

Report of the Public Staff on the
Minimum System Methodology of
North Carolina Electric Public Utilities

Report of
March 28, 2019

## Table of Contents

# I. Purpose of Report and Background

Pursuant to the Commission's *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* issued in Docket No. E-7, Subs 819, 1110, 1146, and 1152, dated June 22, 2018 (2018 Rate Order), the Public Staff presents this report on its findings concerning the use of the minimum system methodology (MSM). Ordering Paragraph 38 of the 2018 Rate Order stated:

> "That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose."

In compliance with the Commission's 2018 Rate Order, the Public Staff held meetings with Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Dominion Energy North Carolina (DENC). At his request, the Public Staff also met with David Neal, the attorney representing the North Carolina Justice Center (NC Justice Center), North Carolina Housing Coalition (NC Housing Coalition), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) (collectively, NC Justice Center, et al.) to discuss the use of the MSM going forward.

After its initial meeting with the electric utilities, the Public Staff requested DEC, DEP, and DENC to provide the following information in written responses:

1. Provide an overview and explanation of the current methodology for distribution plant classification.
2. Provide the history of the Company's use of the Minimum System.
3. Provide the history of allocating distribution costs as demand- and customer-related.
4. Explain the Company's current allocation of distribution costs and why it is appropriate.
5. Should the basic customer method of allocating costs be adopted?
6. Explain any other options for allocating distribution costs as customer- or demand-related.
7. Provide the Company's recommendations.

The responses to these initial questions are shown in Appendix 1.

The Public Staff conducted additional discovery on DEC, DEP, and DENC regarding their approach to the MSM, calculations, and application. The Public Staff also reviewed information provided by Mr. Neal regarding the allocation of distribution plant and the MSM.

The Public Staff also reviewed the National Association of Regulatory Utility Commissioners' "Electric Utility Cost Allocation Manual" (NARUC Manual), published in January 1992, for guidance on the allocation of electric utility costs. The NARUC Manual continues to be considered an important resource for the calculation and allocation of electric utility cost of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost-of-service and rate design.

## II. Overview of the Distribution System

The distribution portion of the typical electric power system is composed generally of wires, substations, transformers, and service connections that bring power to end-use consumers at a usable voltage level. Power generation resources are typically interconnected to the electric system by means of high voltage (100 kV and greater) transmission lines. Transmission-to-distribution substations "step down" these high voltages to what is recognized as the distribution components of the power delivery system. Customer meters represent the point at which the customer takes electric service from the utility. For accounting purposes, physical assets associated with the distribution system are assigned to specific FERC accounts and identified in cost of service studies,[1] as illustrated in Table 1.

**Table 1. FERC Accounts Related to the Distribution System.**

| FERC Account | Distribution Asset |
|---|---|
| 360-363 | Substations & Equipment |
| 364 | Poles, Towers, Fixtures |
| 365 | Overhead Conductors & Devices |
| 366 | Underground Conduit |
| 367 | Underground Conductor & Devices |
| 368 | Line Transformers |
| 369 | Service Connections/Drops |
| 370 | Meters |

[1] See Appendix 2 for a more detailed list and description of equipment included in each FERC account.

Residential customers, small to medium load non-residential customers, and most street and area lighting customers receive electric utility service from the distribution system. Larger non-residential customers, such as industrial customers, may receive service from either the distribution or transmission systems. This is an important distinction in the allocation of costs related to the distribution system. Under all cost-of-service methodologies, only customers receiving service at the distribution level are allocated costs associated with the distribution system.

## III. Overview of the Cost of Service Study

The cost-of-service study (COSS) is a tool for calculating and demonstrating how utility costs are functionalized, classified, and allocated or directly assigned among jurisdictions and customer classes. Without this basic tool, the utility, its customers, and other interested parties are unable to establish the cost and revenue relationships the Commission relies upon to determine just and reasonable rates.

Data used in a COSS is based on the official accounting books and records of the utilities. This data includes the number of customers and meters, the demand or capacity (kilowatts or kW) recorded during peak load periods, and the total energy (kilowatt-hours or kWh) used to serve each customer class, all of which ultimately drive the costs that each jurisdiction and customer class imposes on the utility system. Much of this data has historically been obtained through load research and direct measurement. However, with the deployment of advanced metering infrastructure (AMI) and the availability of more granular AMI data, utilities are able to ascertain more clearly and specifically how their customers utilize, and impose costs on their systems, and how rates can be designed to better reflect the true cost causation of utility service provided.

The four major steps in developing the COSS are: (1) the functionalization of the utility system; (2) the classification of costs; (3) the determination and definition of the customer classes; and (4) allocation of costs to jurisdictions and customer classes. The end result of this exercise is the calculation of a revenue requirement and return on rate base for each jurisdiction and customer class, which will serve as the foundation of rate design.

The first step, functionalizing the utility's costs, is used to categorize the costs associated with each major electric utility service function. This includes the production (generation) facilities needed to meet peak loads and generate required energy; high voltage transmission facilities to interconnect production facilities with the distribution system; distribution facilities needed to step down voltages to usable levels for most customers and to interconnect customers; and customer services such as metering, billing, and account management.

The second step, classifying each functionalized cost category, identifies costs as either the result of electric use or by the number and type of customer. Costs driven by electric use can be characterized in one of two ways: demand or energy. Electricity demand is measured in kilowatts (kW) and represents a rate of use. The measurement of demand is similar to the speedometer of a car, which registers how fast you are driving at any point in time. Just as car speed can vary from moment to moment, so can demand for electricity. Energy is measured in kilowatt-hours (kWh) and is a measurement of demand over time. Energy use is analogous to the car's odometer. Just as the car's odometer measures the total distance travelled in miles, measurement of energy usage reflects total electricity consumption over a period of time, typically a billing period. There are specific costs incurred by a utility related to a customer's demand (rate of energy use), as well as other costs that relate to a customer's total energy usage. Functionalized costs are typically classified as follows:

**Table 2. Classification of Electric Utility System Components.**

| Cost | Demand | Energy | Customer |
|---|---|---|---|
| Production | X | X | |
| Transmission | X | | |
| Distribution | X | | X |
| Customer | | | X |

The third step identifying the characteristics of the customer classes and rate schedules, to determine how customers will pay for utility service. Customer classes are developed from loads and load shapes of customers with similar usage characteristics.[2] Traditional COSS have generally identified customers as residential, non-residential or general service, industrial, and lighting. However, it is likely that additional customer classes will need to be established as the availability of AMI data will provide greater clarity into the variety of customers that are interconnected to the electric utility system.

The fourth step, assigning or allocating each cost to jurisdictions and customer classes, determines who pays for certain costs. Some costs are directly assignable to a particular jurisdiction or customer class because they are easily identified with a particular jurisdiction, customer class, or individual customer. Costs that cannot be directly assigned must be allocated based on their function and classification. Such costs are typically allocated using the demand, energy, and customer data determined earlier for the COSS. Costs that have been classified as production or transmission costs are allocated to the jurisdictions and customer classes, at least in part, on the basis of a peak demand factor. Distribution-classified costs are directly assigned to jurisdictions. However, the jurisdictional assignments are allocated to the customer classes based on non-coincident peak demand and the number of customers.

[2] The availability of AMI data is beginning to provide a better understanding of customer usage and load shapes that traditional load research could only estimate. A challenge going forward will be how to utilize new AMI data to determine whether the traditional classification of customers is appropriate for the widening variety of end-users that are presently classified as "residential" and "small general service." Once available, this data should help utilities and regulators to design rates that better reflect cost causation and reduce the potential for cross-subsidy among customer classes.

All costs incurred by the utility must be considered in the COSS, otherwise the utility is not able to reasonably recover its full costs to serve all of its customers. The COSS seeks to ensure that all jurisdictions and customer classes bear appropriate responsibility for the costs they impose upon the system. These cost causation principles serve as the foundation of rate design and should always represent the starting point for the rate designer to calculate and establish rates.

The selection of the methodology or approach to cost-of-service is a critical first step in the development of a COSS. The methodology is often a contentious issue among parties in a general rate case proceeding and has significant bearing on the development of a COSS and the allocation of production and transmission-related costs. The methodology selected dictates the process of calculating demand factors that are used in the allocation of demand-related costs. Some examples include a demand-only method based on the use of a single or multiple coincident peaks, versus a method that employs a weighted method using peak demand and energy to allocate certain costs of production and transmission. While not a subject of this report, the selection of a COSS methodology establishes a framework for the COSS itself and provides guidance on the relationships of demand, energy, and the number of customers that the rate designer will use to set rates for service.

## IV. <u>Overview of Rate Design</u>

The general purpose of electric utility rates is to produce revenues for service rendered. The purpose of a specific rate design is to ensure that the utility has a reasonable ability to recover its costs, provide a fair return to its shareholders, attract capital for future investment, and encourage efficient energy use. This report is focused on two principles and objectives that apply primarily to rates and rate schedules for residential and small general service customers, namely the classification of distribution costs as either "demand-related" or "customer-related" and the establishment of a basic customer charge that fairly and reasonably recovers costs.

The COSS informs rate design. The first step following the development of the COSS involves the determination of jurisdictional and customer class returns on rate base and associated revenue requirements. The second step involves the determination of demand, energy, and customer related components by jurisdiction and customer class. In addition, an understanding of the relationships of fixed versus variable costs, and marginal versus average costs, among others, is critical to ensuring that individual rate elements (e.g., basic customer charge, demand charge, energy charge, etc.) within a particular rate schedule are maintained as close to cost causation as possible.

For example, as a general rule, energy costs (costs measured on a per kWh basis) are recovered based on total energy (kWh) consumption. These costs typically consist of the cost of fuel consumed in electric generating plants, as well as other fuel-related (e.g., reagents) or energy-related (e.g., variable operating and maintenance costs and costs stemming from the production of coal combustion by-products) costs that are the direct result of operating the electric generating plants.

Likewise, demand costs (costs measured on a per kW basis) should be recovered based on some measurement of maximum demand (kW) at a particular point in time. Demand-related costs may be incurred and recovered based on a customer's maximum demand placed on the electric utility's entire system (e.g., on the generation units or the transmission system), often referred to as a "coincident peak demand" (CP), or based on demand placed on a more localized part of the electric utility system (e.g., the distribution system), often referred to as a "non-coincident peak demand" (NCP).

For generation and transmission assets, an individual customer's demand is typically measured as their contribution to total demand at the time of the utility's maximum aggregated demand (maximum demand of its customers, both wholesale and retail, at a single point in time). Generating plants and transmission assets are sized to meet a maximum system load, which is diversified and may or may not occur at the same time as the maximum demand of an individual customer of the utility.

For demand-related distribution assets, an individual customer's demand is typically measured as their contribution to the customer class maximum demand regardless of when it occurs relative to the maximum system demand. Some distribution assets are sized to meet a geographically localized maximum demand (e.g., primary conductor wires, distribution substation transformers) while other distribution assets are sized to meet the individual customer's maximum demand (e.g., distribution service transformers). However, distribution costs have both demand-related and fixed characteristics. While distribution related costs must be sized to meet some level of maximum demand, there is also a <u>minimum</u> cost for the distribution system that must be incurred regardless of demand.

In addition to the cost causation principles outlined above, the rate designer is also challenged with navigating different, often conflicting considerations. Those considerations are typically addressed in a general rate case and may include:

- Simplicity of rate designs;
- Rate and revenue stability;
- Migration of customers between rate schedules;
- Recovery of fixed and variable costs;
- Avoidance of rate shock;
- Mitigation of rate shock without exacerbating cross-class subsidies;
- Policy objectives that have been established by statue, rule, or prior Commission order;
- Innovative versus traditional rate designs;
- Appropriate price signals to customers; and
- Encouraging the efficient use of electricity.

The rate designer does not have the luxury of starting with a "clean slate" to meet all of these cost causation principles and other considerations. Many legacy rate schedules maintain rate designs that do not reflect many of today's energy realities.[3] For example, the basic residential rate schedule, which covers 90% of all residential customers, only utilizes two rate elements – a monthly flat basic customer charge and a per kWh energy charge. Any fixed costs not recovered from the flat monthly customer charge must be included in the variable energy charge. This traditional design was implemented for practical reasons, not for cost causation or theoretical rate design reasons. The recovery of fixed and non-energy variable costs through an energy charge leads to cross-subsidization within the residential class of customers. The ease of administering this rate design has been considered an acceptable trade-off until recently.

## V. History and Use of the Minimum System Method in Classifying Distribution System Costs

Cost-of-service analysts have traditionally recognized that costs associated with the distribution system exhibit characteristics that are both demand- and customer-related. The most basic, and least controversial, representation of customer-related distribution costs are those associated with facilities closest to the customer's point of delivery (e.g., the meter and service drop wires). However, the meter and service drop wires must be connected to the broader electrical grid in order to deliver energy to a customer. The distribution grid must be designed to be capable of meeting the maximum level of electrical demand placed on it by customer loads. The question then becomes, how much of the distribution grid should be considered demand-related versus how much should be considered customer-related, for cost recovery purposes? Historically, North Carolina's regulated electric utilities have relied on the MSM to answer this question.

The Public Staff reviewed Commission orders to gain an understanding of the history related to COSS and the application of MSM to the electric utilities. Our review focused on orders from the late 1960s and early 1970s, when Commission orders began to include detailed discussion of cost-of-service. At that time, electric utilities were experiencing significant growth in the demand for electric utility service and the need to build capacity to meet those demands, causing significant upward pressure on rates. The orders reflect that the Commission was concerned not only with the need to serve new electric demand, but also the need to balance the increasing costs between new and existing customers, as well as equitably balancing the rates of growth between residential and non-residential customers. While not an exhaustive list (see Appendix 3), the Public Staff notes several Commission orders that provide some foundation for the COSS, recognition that distribution system costs are both demand- and customer-related, and the use of MSM in apportioning distribution system costs. The Commission's June 28, 1973 Order in Docket No. E-22, Sub 141 was the only order found by the Public Staff that provides specific direction for calculating and applying the MSM. Since that time and until recently, the MSM has not been an issue that received prominent attention in Commission proceedings, even though there were numerous general rate cases in the 1970s and 1980s.

[3] Energy efficiency programs, net metering, enhanced data, smart appliances, etc.

The MSM has also served as a foundation for establishing the flat monthly basic customer charge. Since the early 1970s, electric utilities have supported their requests to increase customer charges on the COSS determination of "customer-related" costs. There is no evidence to suggest utilities have ever requested a monthly customer charge that reflected the total cost per customer that was determined to be "customer-related" via the MSM.[4] In addition, the Public Staff is not aware of any case where it supported, or the Commission granted, a basic customer charge increase to reflect the total amount of costs designated as customer-related in a MSM study.

## VI. Methods Used to Classify Distribution Costs

As stated above, there is broad consensus that the distribution system is comprised of equipment that is both demand- and customer-related; however, there is little consensus on the calculation and determination of the portions classified as either demand- or customer-related.[5,6] In order to classify the distribution system components, the utilities use a method that defines the scope and purpose of each component of the distribution system as it relates to demand and customers.

The NARUC Manual dedicates a full chapter on the classification and allocation of distribution plant, including what amounts to the best explanation and description of the two approaches to classifying distribution costs – the minimum-size method or the minimum-intercept method (also called zero-intercept). Another approach, known as "basic customer method" has been discussed in recent general rate cases before the Commission. Each of these approaches is briefly discussed below.

### A. Minimum-Size Method

According to the NARUC Manual, the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the utilities' customers.[7] This involves a determination of the minimum sizes of poles, conductors, cables, transformers, and services installed by the utility. An average unit cost for each minimum-size piece of equipment is then determined and used to calculate the total cost for the entire inventory of equipment installed. The total cost of this equipment is then classified as "customer-related" costs. The "demand-related" portion is defined as the difference between the total investment in similar equipment and the customer-related portion.

[4] The most recent rate case for each utility is - Docket Nos. E-2, Subs 1023 and 1142; E-7, Subs 1026 and 1146; and E-22, Subs 479 and 532.

[5] "New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World," P. Morgan and K. Crandall, EQ Research, LLC, April 2017.

[6] P. 29, "Charging for Distribution Utility Services: Issues in Rate Design", December, 2000, Frederick Weston, The Regulatory Assistance Project, (Weston Report).

[7] P. 90, NARUC Manual

B. Minimum-Intercept Method

The minimum-intercept method attempts to identify and quantify the portion of the distribution system that would correspond to a hypothetical “zero-load” or “zero-intercept” situation.[8] The NARUC Manual recognizes that the minimum-intercept method is theoretically the most accurate; however, it requires significant data to calculate. As part of the calculation, a cost curve is developed for existing equipment of various sizes and loads. Regression analysis is then applied to the curve to calculate the point at which the trend line intersects the cost axis. The value at the intersection represents the "zero-load" cost. The "zero-load" cost per unit of equipment is then applied to each quantity of distribution equipment, regardless of size, to determine a total cost of zero-load equipment. The ratio of the zero-load costs to the actual total investment in equipment is determined to be "customer-related". The remainder is considered to be "demand-related."

C. Basic Customer Method

The basic customer method is not included in the NARUC Manual, but was introduced by intervening parties participating in recent general rate cases. The basic customer approach classifies 100% of all poles, wires, and line transformers as "demand-related" costs.[9] All other costs (those related to meters and service connections) are classified as "customer-related."[10,11]

## VII. Minimum System Method Calculations Used By North Carolina Electric Utilities

The utilities each have slightly different approaches to calculating the MSM for classifying their respective distribution systems as demand- or customer-related. While all three have adopted a minimum-size approach, the differences cause the individual calculations for each utility to yield different results. The differences include variation in the size of individual pieces of equipment, specific unit costs of that equipment, and the mathematical calculations. The methods used by each utility are discussed below.

A. DEC

DEC describes its approach for FERC Accounts 364, 365, 367 and 368 as a "modified minimum-size method." Instead of using actual, historical embedded costs of distribution plant, DEC estimates the current cost of a minimum system needed to support minimal load, based on assumptions and concepts that are consistent with the NARUC Manual. It then discounts those costs to simulate a vintage of historical embedded cost

[8] P.92, ibid.
[9] P. 30, Weston Report.
[10] P. 34, ibid.
[11] The Weston Report also makes general reference to substations and substation equipment and indicates that this equipment is all "demand-related." However, the Weston Report is silent on the classification of underground equipment and conduit.

of the minimum system. This simulated value is then multiplied by the total inventory of equipment in each FERC account for the current year. The result is then de-escalated based on the age of the equipment using a Handy-Whitman Index for the average year the equipment was placed in service. A comparison to the current year's value is then made.[12]

As a second step, an index is calculated using the mid-year weighted average age of equipment. The average weighted age is then computed by dividing the sum of the weighted ages by the sum of all vintage costs for the equipment. The resulting weighted average age is then subtracted from the current year. The year calculated is then used to determine the Handy-Whitman average age index value for that year.

The third step involves taking the Handy-Whitman index value for the average age and multiplying it by the current year minimum costs determined in the first step to obtain the average historical cost. This value is then multiplied by the total inventory of equipment to produce a minimum installed cost. This amount represents the customer-related portion of the FERC account balance.[13]

DEC considers 100% of FERC Accounts 366, 369, and 370 to be customer-related; 100% of FERC Accounts 360, 361, and 362 to be demand-related; FERC Account 363 is not applicable to DEC.

B. <u>DEP</u>

The approach used by DEP in its most recent rate cases to estimate the minimum system for FERC Accounts 364, 365, 367, and 368 is slightly different from that used by DEC. DEP has relied on a 2010 study,[14] rather than the method employed by DEC that uses actual plant adjusted based on age. DEP indicated that the results of both the DEC method and DEP method produce comparable results; however, DEP acknowledges that its calculation is more complex and time-consuming than DEC's approach, and since they produce similar results, DEP plans to incorporate the DEC method of calculating the minimum system in future rate cases.

C. <u>DENC</u>

DENC has generally followed a method for calculating the minimum system as established by the Commission's June 28, 1973 Order in Docket No. E-22, Sub 141 (Sub 141 Order). That order prescribed the use of minimum system approach for FERC Accounts 364, 365, 367, and 368. The distribution line portion of FERC Account 360 was to be classified as 100% customer-related, while FERC Account 369 consisted of

[12] The Handy-Whitman Index calculates the cost trends for utility construction.

[13] Based on the explanation found on pages 7 and 9 of the report provided to the Public Staff on November 8, 2018. The same process is calculated for each applicable FERC account balance. There is some variation of this process for FERC Accounts 365, 367, and 368, but the general process is applied to all FERC accounts. A more thorough description is provided in the report itself, which is attached as Appendix 1.

[14] The Public Staff believes this study is a study of distribution system assets.

minimum-sized overhead and underground cable/conductors. The remaining FERC distribution accounts (361, 362, 363, and 366) were not specifically addressed in the Sub 141 Order.

DENC currently uses a MSM based on taking baseline material unit costs and then scaling these unit costs up to the size of the existing distribution system to calculate the customer-related component. More specifically:

- FERC Accounts 360 and 361: Ratios are developed between the overhead and underground components using the delineation of demand-related and customer-related components calculated via minimum-intercept for FERC Accounts 364, 365, 366, and 367. The sum of the customer-related portions of these accounts is used to calculate the percentage of demand-related and customer-related portions of overhead and underground, and primary and secondary account balances, which are then applied to the total balance for Accounts 360 and 361.

- FERC Account 362 and 363: DENC considers 100% of FERC Account 362 to be demand-related; FERC Account 363 is not applicable to DENC.

- FERC Account 364: DENC uses the embedded historical unit cost of a 35-foot pole[15] as determined from Company records. This amount is then multiplied by the total number of poles at primary and secondary levels to determine the customer-related amount for FERC Account 364. The demand-related portion is calculated as the difference between the total balance of FERC Account 364 and the customer-related amount.

- FERC Account 365: DENC uses 4/0 and under wire[16] as the minimum-size component for overhead conductors. The embedded historical unit cost of one pound of 4/0 and under wire is determined from Company records. Using a pounds/foot estimate for the wire, this unit cost is multiplied by the number of wire-feet of conductor in the existing distribution system (at primary and secondary levels) to determine the customer-related portion of FERC Account 365. The demand-related portion is calculated as the difference between the total balance of FERC Account 365 and the customer-related amount.

- FERC Accounts 366 and 367: DENC uses the cost of #4 underground primary cable for primary distribution or #8 secondary cable for secondary distribution as the minimum-size components.[17] Both costs are calculated using regression analysis. The present day unit cost for each size of cable is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost for each size of cable is multiplied by the total circuit feet of primary and secondary cable, respectively,

[15] Ordering paragraph 7d in the Sub 141 Order.
[16] Ordering paragraph 7e in the Sub 141 Order.
[17] Ordering paragraph 7f in the Sub 141 Order.

to determine the basis for the customer-related portions of primary and secondary cable. The demand-related portion is calculated as the difference between the total balance of primary and secondary costs, respectively, of FERC Account 367 and the customer-related amounts. The same percentages determined for FERC Account 367 are then applied to FERC Account 366.

- FERC Account 368: DENC uses the cost of a zero-intercept transformer as the minimum system component. This zero-intercept unit cost is multiplied by the total number of transformers to determine the customer-related portion of FERC Account 368. The demand-related portion is calculated as the difference between the total balance of FERC Account 368 and the customer-related amount.

- FERC Account 369: DENC calculates the customer-related portion of this account separately for overhead and underground service drops. The minimum-size component of an overhead service is 80 feet of #2 aluminum service conductor.[18] The present day unit cost for this service is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost is multiplied by the total number of overhead customers to determine the customer-related portion. For underground services, DENC uses a #8 service conductor[19] from the pad or pole to the facility (calculated using regression analysis). The present day unit cost for underground service is scaled to an estimated historical cost for the system using a de-escalation factor based on the Handy-Whitman Index. The resulting unit cost is multiplied by the total number of underground customers to determine the customer-related portion. The sum of each customer-related amount (overhead and underground) is subtracted from the total balance of FERC Account 369 to determine the demand-related amount.

- FERC Account 370: DENC considers 100% of FERC Account 370 to be customer-related.

## VIII. Public Staff's Policy Objectives for Cost-of-Service and Rate Design

The Public Staff's objectives regarding cost-of-service and rate design have incorporated the central tenet that the electric utility system is planned, built, and operated on the basis of providing safe and reliable electric utility service at the least reasonable cost possible, while meeting both the capacity and energy needs of the consuming public.

The Public Staff has advocated that cost-of-service should be the foundation of establishing the appropriate apportionment of the revenue requirement. Once the revenue requirement is calculated, it must be apportioned among the customer classes. The process of apportioning the revenue requirement then relies upon the overall

[18] Ordering paragraph 7h in the Sub 141 Order.
[19] Ibid.

jurisdictional return on rate base (ROR) that is calculated for the utility. The Public Staff continues to believe that the apportionment among the classes should accomplish four goals:

- Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

- Maintain a ±10% “band of reasonableness” for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;

- Move each customer class toward parity with the overall jurisdictional ROR; and

- Minimize subsidization of customer classes by other customer classes.

## IX. <u>Public Staff’s Conclusions and Recommendations</u>

The establishment of the proper fixed charge component of electric rates, also called the basic customer charge, has been an issue since the late 1960s and continues today. Parties advocating positions in general rate cases have based their positions on the COSS to support their individual points-of-view. Utilities have frequently advocated basic customer charges that trend more toward the full customer value identified in COSS calculated using the MSM. Other parties have advocated for a method that minimizes the classification of distribution costs that are customer-related.

The Public Staff has traditionally advocated a position that supported a basic customer charge based on the utilities' MSM, while recognizing that full movement would likely result in rate shock for many customers, particularly low-income and low-usage customers.

Trends in utility service that indicate more customer-owned generation is being installed and that those customers are buying less energy from the utilities further exacerbates the fixed cost recovery equity issue, leading to higher energy charges as utility sales diminish. Such a reality will have a significant impact on low-usage and low-income customers if all customers are not equitably participating in the recovery of fixed costs. While sales may decrease, fixed costs will likely not.

As a result of the examination of MSM, the Public Staff believes there are fixed costs of electric service that should be recovered from all customers; however, we acknowledge that there is a debate over the extent to which the costs[20] of electric utility service are fixed. Utilities tend to suggest that a significant portion of the costs incurred to provide utility service is fixed.[21] However, many economists suggest that, over the long-run, most costs are not fixed.[22, 23] This debate is difficult to reconcile because on the one hand, the utility's cost-of-service and the rates charged to recover these costs, are typically the result of a short-term perspective. In other words, utilities collect revenues from rates that remain static only until the next general rate case or rider proceeding. On the other hand, capital investments in utility service are long-lived, and often "lumpy"[24] investments, intended to provide service for 25 or more years.

The Public Staff believes that certain aspects of utility service, and the associated costs, are fixed. Once capital investments are made and the equipment is deemed used and useful for utility service, those costs are incorporated into the utility's revenue requirement calculations and will remain there until fully recovered.

All customers should bear some responsibility for the fixed costs of utility service. Fixed costs are incurred to produce, transmit, distribute, and administer electric utility service and are essential components of that service. Any utility customer interconnected to the utility's transmission and distribution grid for the purpose of receiving electric service should be responsible for some portion of fixed costs. Customers who are able to avoid contributing toward the recovery of fixed costs through the modification of consumption patterns are shifting costs incurred to serve them to other customers and customer classes.

The Public Staff is concerned about the impact of fixed cost recovery on low-income customers. Increases in fixed charges can disproportionately impact low-income and low-usage customers. However, the Public Staff believes that any efforts undertaken by the electric utilities to help low-income customers should be narrowly tailored, rather than setting fixed cost recovery artificially low. Considering any revenue not recovered in the fixed charge is recovered in the energy charge, setting the fixed charge too low results in a disproportionate increase on low-income customers that are also high-usage customers.

After our review, the Public Staff believes[25] that the use of MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for

[20] The Public Staff considers fixed costs to be those that do not materially change in proportion to the delivery of capacity, energy, or the number of customers.

[21] See responses in Appendix 2.

[22] P.336, "Principles of Public Utility Rates," Public Utilities Reports, Inc., Bonbright, James C., Columbia University Press, New York, 1961.

[23] "Caught in a Fix – The Problem with Fixed Charges for Electricity," Synapse Energy Economics, Inc., February 9, 2016.

[24] An investment's "lumpiness" refers to the fact that it cannot be added in discrete increments to just match incremental demand requirements. Examples are baseload generating plants, substations, and transmission and distribution networks.

[25] The position of the Public Staff in any future rate case is dependent on the application filed in that case. The Public Staff reserves the right to develop a new or different position concerning the MSM in any future proceeding before the Commission.

establishing the maximum amount to be recovered in the fixed or basic customer charge. While not precise, MSM is a logical methodology for classifying costs of a distribution system as demand- or customer-related. However, the Public Staff believes the following principles should also be applied in establishing the fixed charge:

- The minimum amount recovered in the fixed charge for any rate class should be an amount determined by the "basic customer method" which reflects the customer meter, service drop, and any other facilities uniquely attributable to specific customers that are not already recovered through extra facilities charges.[26]

- Any increase in the fixed charge for any rate class should not exceed an amount that would recover more than 25% of the revenue increase that was assigned to that customer class.

The Public Staff also recommends:

- That future cost-of-service studies should be designed to provide a more accurate picture of the fixed costs of utility service, both as an aggregate cost to each customer class, and on a dollar per customer, dollar per kW of demand, and dollar per kWh basis. The Public Staff believes this will begin to provide information on the costs that are truly unavoidable, as well as provide a different perspective of any cross-subsidy issues among the customer classes. The Public Staff also believes this will provide vital information regarding the amount of any basic customer charge or other unavoidable charge that may be established.

- That cost causation principles in cost-of-service studies and rate design should be balanced with efforts to provide relief to low income customers. Any effort to provide relief to qualifying low-income customers should be considered separate from the setting of the general fixed cost recovery in a rate class.

- That utilities utilize data gained from AMI meters to implement rate design changes, including new customer classes, demand charges for all rate classes, and new rate designs.

- That the Commission should request that NARUC, or some other independent entity, undertake a study of these issues from a national perspective, so as to gain insight from best practices and ideas across the country.

[26] Extra Facilities Charges are typically those charges associated with equipment that must be installed at or near the point of delivery due to the unique customer loads.

## I. Introduction

In the evidentiary hearings in Docket No. E-7, Sub 1146 In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable for Electric Service in North Carolina, there was considerable testimony and cross-examination of witnesses around Duke Energy's use of the minimum system approach to allocate distribution plant and its basic facilities charge. In its order dated June 22, 2018 in this Docket, the North Carolina Utilities Commission approved Duke Energy Carolina's use of the minimum system concept for cost allocation in that proceeding. The North Carolina Utilities Commission also ordered as follows:

> 38. That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

The Public Staff conducted a meeting in its offices on September 11, 2018, and invited representatives of both Duke Energy and Dominion Power to participate. At this meeting, each electric utility presented an overview of its approach to calculating the minimum system. Following these presentations, the Public Staff asked each utility to respond within 60 days to the following questions:

- Overview of current company allocation of distribution costs.
- History of the use of minimum system, including any proceedings and orders where Commission has discussed minimum system for each utility.
- History of allocation of distribution costs as "demand-related" and "customer-related."
- Explain the Company's current allocation of distribution costs and why it is appropriate.
- Whether or not the basic customer method of allocating costs should be adopted.
- Other options for allocating distribution costs as customer or demand-related, and other methods for setting the basic customer charge.

The purpose of this report, therefore, is to provide Duke Energy Carolina's and Duke Energy Progress's ("Duke Energy") response to the Public Staff's information request.

## II. Overview of Current Company Allocation of Distribution Costs

The distribution system can be described as that part of the electric system from the primary bus of the general distribution substation that reduces high voltage to a lower level that can be transmitted through the distribution system all the way through to the customer's premises. From an allocation perspective for minimum system purposes, however, the distribution system consists of (1) primary lines and poles that distribute the power (2) distribution transformers which reduce the voltage from a distribution voltage to a voltage capable of operating customer equipment and (3) secondary lines and services to deliver electricity to the customer's premises. The general distribution substation is installed and located primarily to meet customer demand and therefore doesn't have a customer component.

Distribution systems are designed primarily to support connection to individual customer sites and are sized with sufficient capacity to meet customer demand. That is, they are built to serve a single customer or group of customers based on anticipated demand in the general location of the facilities. In addition, transformers, poles and wires are needed to connect to each individual customer in a specific area. Lastly, facilities must be sized to allow the customer to receive sufficient energy to meet their own power needs but also the power needs of all customers served from the circuit. Duke Energy has therefore concluded that the distribution system is constructed primarily to connect to individual customers but also must have sufficient capacity to serve the collective load on the circuit. Therefore, the allocation of distribution plant has both a clear customer and demand component.

The table below is excerpted from a Duke Energy Carolina's (DEC) cost of service study. It demonstrates that distribution plant-in-service for FERC Account 364 – Overhead Poles, Towers & Fixtures not directly assigned to a customer class is allocated across all customer classes using non-coincident demand and customer allocation factors. Note also that this account has been further subdivided between primary and secondary plant to ensure that customers served at the higher primary voltage level are not assigned costs for the secondary system that does not serve them. Lastly, this account also includes two components that are labeled "MIN SYS" or minimum system. A discussion of how these minimum system dollar amounts are derived is contained in a later section of this report.

| Account | Jurisdictional Allocator | Customer Class Allocator |
|---|---|---|
| 364 DISTR PLANT-POLES-EXTRA FAC | Direct Assign | Direct Assign |
| 364 DISTR PLANT-POLES-PRI CUST-MIN SYS-NCR | Direct Assign | All - Cust Num Pri x OL |
| 364 DISTR PLANT-POLES-PRIMARY DMND-NCR | Direct Assign | All - NCP Pri |
| 364 DISTR PLANT-POLES-SEC CUST-MIN SYS-NCR | Direct Assign | All - Cust Num Sec x OL |
| 364 DISTR PLANT-POLES-SECONDARY DMND-NCR | Direct Assign | All - NCP Sec |

This same basic approach is used for all the distribution plant accounts from FERC Account 364 through FERC Account 368.

## III. History of the use of minimum system, including any proceedings and orders where Commission has discussed minimum system for each utility.

In its order dated June 21, 1973 in DOCKET NO. E-7, SUB 145 In the Matter of Application of Duke Power Company for Adjustment of Rates and Charges Applicable for Electric Service in North Carolina, the North Carolina Utilities Commission stated:

> The commission staff made a full and complete investigation of the 1971 cost-of-service study. Staff Witness Clapp testified on the manner of execution of Duke's 1971 study and made recommendations for changes in future studies. The use of the minimum-intercept method of calculating certain of the consumer components of distribution costs was recommended by the staff in order to refine the accuracy of the study and produce more stable and comparable results over time. Mr. Clapp testified that the Duke cost-of-service study followed some of the methods which are outlined in a forthcoming NARUC publication on the subject, that the staff had examined the treatment of each account in the study as to the appropriateness of its use, that only two accounts required adjustment and that, overall, the Duke Study did not require adjustment. Staff revised the 1971 cost-of-service study to reflect the use of statistical regression techniques and the minimum-intercept method in the allocation of poles (on the basis of average height, average year, and Class 7 size intercept) and transformers (a zero-load intercept). The recommendations made by the staff, and the revision of that 1971 cost-of-service study to conform to the staff recommendations were not challenged.

Under a Finding of Fact, the North Carolina Utilities Commission found that:

> 22. That the use of the minimum intercept method of calculating customer components of distribution plant produces more correct and more stable and comparable results over time than the minimum-size method.

In its order dated June 28, 1973 in DOCKET NO. E-7, SUB 141 In the Matter of Application of Virginia Electric and Power Company for Authority to Increase Its Electric Rates and Charges, the North Carolina Utilities Commission found that:

> (7) That VEPCO shall complete and file with the Commission annually on April 30 a Cost of Service Study detailing the rate of return earned by each class of service, and the customer, demand and energy components of revenue deductions and net plant investment, and allowance for working capital; that such studies shall be based upon each calendar year's operations; that demand data used shall have been taken within two years of the end of the period under study; that the methods of execution of cost of service studies shall be determined by the Company with the goals of accuracy, responsible allocation, and stability over time; and that studies based upon alternative methods may be submitted for consideration, but that at least one shall be based upon the following:
>
> (a) Sizes of distribution plant used in computation of customer components shall be the minimum sizes which will meet the requirements of the National Electrical Safety Code and other like restrictions, and costs for such sizes of equipment shall be actual costs, if available, or shall be computed using statistical regression techniques and the minimum-intercept method.
>
> (b) Coincident demands shall be measured at the time of daily system peaks, and that demand data taken at the time of the top five daily system peaks (if all five are within 1/2% of the yearly system peak) shall be averaged to calculate the coincident demand factors to assure proper assignment of `coincident peak responsibility.
>
> (c) -The distribution line portion of Account 360, Land and Land Rights, shall be allocated on customers only.
>
> (d) Account 364 - Poles, Towers, and Fixtures, shall be allocated to primary and secondary based upon the number of wires on each pole in the sample, weighted by the relative difference in wire sizes, and all neutrals shall be allocated to the primary, that if poles are initially installed oversized to carry planned later wire additions, the final design shall, if possible, be used in the above allocation, and that the Minimum Intercept cost of a Class 7 pole shall be used when computing the customer component.
>
> (e) The calculation of the customer component of Account 365 - Conductors, shall be based upon two-wire secondaries and primaries and three-wire joint secondary\primary lines, and that the Minimum Intercept cost of #4 ACSR or equivalent shall be used.
>
> (f) The calculation. of the customer component of Account 367 - Underground Conductors and Devices, shall be based upon #4 Al UG cable primary and #10 Cu or #8 AI duplex 600 V UG cable (or such cable as to carry a minimum load). for secondaries.
>
> (g) The calculation of the customer component of Account 368 - Transformers, shall be based upon a 0 KVA Minimum Intercept.
>
> (h) The calculation of the customer component of Account 369 - Services, shall be based upon #4 EC, #ACSR,#I0 AD Cu., or #12 MHO Cu for overhead services and #I0 Cu or #8 AI duplex 600 volt UG cable for underground.

In its Order dated August 5, 1988 in DOCKET NO. E-2. SUB 537, In the Matter of Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges on page 130 the North Carolina Utilities Commission stated that:

> In this proceeding, the Company proposed to discontinue the use of its minimum system technique for allocating a portion of distribution plant between customer classes. CIGFUR-II, the Department of Defense, and the Public Staff recommended that the minimum system technique be retained. The minimum system technique derives the cost of distribution plant as if all components of such plant are "minimum" size (i.e., the minimum size needed to connect each customer to the system regardless of the amount of kWh used). The cost of the "minimum" distribution plant is then allocated between customer classes on a per customer basis, while the remainder of the distribution plant cost is allocated between customers on the basis of distribution level kW demand. The Company contended that it is more appropriate to allocate the investment in meters and services on a per customer basis and the remainder of the distribution system on a per kW demand basis. However, such reflection of minimum distribution plant costs in the basic customer charges would result in residential customer charges at least double the current $6.75 per month. The Commission has never approved residential customer charges approaching the levels indicated by the minimum system technique.
>
> The Commission is of the opinion that the minimum system technique should not be discontinued at this time. The minimum system technique allocates more of the distribution plant to residential customers and less to large industrial customers. It is conceptually sound even if the results are not fully reflected in the basic customer charges. Furthermore, retention of the minimum system technique will modify somewhat the impact of the SWPA allocation methodology on the industrial class.

In this order, in its Findings of Fact, the Commission found:

> 14. The Summer/Winter Peak and Average method, Including the minimum system technique, is the most appropriate method for allocating costs between jurisdictions and between customer classes within the North Carolina retail jurisdiction in this proceeding. Consequently, each finding in this Order which deals with the overall level of rate base, revenues, and expenses for North Carolina retail service has been determined based upon the summer/winter peak and average cost allocation methodology as described herein, including the minimum system technique.

In DOCKET NO. E-2. SUB 1023, In the Matter of Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Progress Energy Carolinas, Inc. (PEC) asked to be relieved of the obligation to file 12-month average coincident peak cost allocation studies and summer/winter peak and average cost allocation studies excluding the minimum system technique. In its Order dated September 25, 2012, it was ordered:

> Based upon PEC's Motion and the record in this docket, the Chairman is of the opinion that good cause exists to relieve PEC of the obligation of filing cost allocation studies using the summer/winter peak and average excluding the minimum system technique, the 12 CP including the minimum system technique and the 12 CP excluding the minimum system technique.

Thus, PEC was required to continue to file cost allocation studies that included the minimum system technique.

Therefore, since 1973, electric utilities serving North Carolina have filed and the North Carolina Utilities Commission has consistently recognized and approved an allocation of a portion of poles, lines and transformers within distribution plant with a customer-related component based on a minimum size concept.

## IV. History of allocation of distribution costs as "demand-related" and "customer-related."

As stated earlier, distribution facilities are designed primarily to deliver electricity to each individual customer but also have the capacity to meet the combined local area loads. One could view a distribution system as a network that radiates outward carrying power to each customer. with ever smaller wires and transformers carrying power to the customer. These distribution networks must be designed to meet their area's maximum peak demand; but as you go further from the substation, lower capacity lines are required since these lines serve fewer customers near the end of circuits. Each component of the distribution system must be designed to meet the maximum anticipated demand of the components "downstream" from it. Due to load diversity, the peak requirement of each individual customer's peak is unlikely to coincide; therefore, the Company must consider both the combined coincidental load on the circuit as well as each customer's individual peak in sizing facilities. This consideration is especially true with distribution facilities close to the customer site such as transformation and secondary circuits which must have sufficient capacity to serve the customer's maximum load in all hours. This diversity of loads is also true with respect to distribution primary capacity since individual circuits don't always experience their highest peak coincident with the system peak for generation and transmission assets. Thus, it is appropriate to allocate distribution plant that is sized to meet demand requirements with a non-coincident peak allocation factor.

Customer-related costs are those that vary based on the number of customers connected to the system. The cost of meters, billing and the customer's service drop are typically accepted by Commissions as customer-related costs since these costs are only incurred to meet an individual customer's electrical needs. Some jurisdictions advocate that the customer charge, a fixed, monthly charge that the customer pays regardless of their usage level, should only include these costs, but this ignores the fact that the basic distribution infrastructure is constructed solely to provide customer connections to the grid.

In the NARUC Cost Allocation Manual, there are two primary methods used to calculate customer-related distribution costs. The first is the "minimum-size" method. This theoretical approach assumes there is a minimum-size distribution system that can be determined to serve a customer's minimum load; such as, one 100-watt light bulb. Once the cost of this minimum system is determined, all costs above this amount are allocated using a demand allocation factor.

The second method is the "zero-intercept" method. This approach attempts to determine the minimum system necessary to provide the customer access to the system without providing any level of demand. Thus, if no demand can be provided, it follows that this portion of the distribution system cannot be demand related. Again, all distribution costs above this minimum amount are allocated using a demand allocation factor. While perhaps theoretically attractive, this method is computationally complex as it requires statistically regressing the installed costs against various sizes of distribution equipment to determine the zero or no-load intercept.

## V. Explain the Company's current allocation of distribution costs and why it is appropriate

Section II of this report describes the basic approach Duke Energy uses in allocating distribution plant costs. However, Section II does not describe in detail how Duke Energy computes the minimum system component of distribution plant costs.

Duke Energy uses a modified minimum-size method. Instead of using the historical embedded cost of distribution plant, which is not readily available, Duke Energy Carolinas estimates the current cost in current year dollars of distribution plant for a minimum system (designed to support minimal usage) based on assumptions and concepts consistent with the NARUC method of minimum system and then “de-escalates” it to simulate a vintage “historical embedded” cost of this minimum system. The table below provides an example of the 2017 Costs Per Mile of Skeleton Plant for Account 364 – Overhead Poles, Towers & Fixtures for Duke Energy Carolina, LLC (DEC) developed by distribution engineering:

| Description | CU | Quantity | Labor | Total Labor | Material | Total Mat |
|---|---|---|---|---|---|---|
| 40/5 poles | POLE-WD-40-C5-C | 23 | 641.59 | 14,756.57 | 153.40 | 3,528.17 |
| Primary Guy | GND-POLE-6-C | 14 | 44.90 | 628.67 | 10.92 | 152.83 |
| | ANCH-PISA-SM-C | 14 | 159.32 | 2,230.52 | 29.50 | 412.94 |
| | GUY-DOWN-3/8IN-GALV-SGL-C | 14 | 105.87 | 1,482.12 | 35.08 | 491.07 |
| | GUY-HOOK-C | 14 | 0.00 | 0.00 | 6.89 | 96.48 |
| | GUY-INSL-7FT-FG-C | 14 | 48.12 | 673.75 | 13.69 | 191.65 |
| | HDWR-MACH-LG-12IN-GALV-C | 14 | 0.00 | 0.00 | 1.93 | 27.03 |
| Extra Guy | GUY-DOWN-3/8IN-GALV-SGL-C | 14 | 105.87 | 1,482.12 | 35.08 | 491.07 |
| | GUY-HOOK-C | 14 | 0.00 | 0.00 | 6.89 | 96.48 |
| | HDWR-MACH-LG-12IN-GALV-C | 14 | 0.00 | 0.00 | 1.93 | 27.03 |
| | | | | $21,253.74 | | $5,514.74 |
| | Total Costs | | | | | $26,768.48 |

This 2017 value of $26,768 per mile is multiplied by the number of miles of overhead line to estimate the overhead line plant balance in FERC account 364 for a minimum system built in 2017. Subsequently, this 2017 plant balance is de-escalated to the weighted average year that plant balance was placed in-service, in order to estimate the minimum system portion of the embedded vintage plant in Account 364. DEC de-escalates this plant balance by employing the Handy-Whitman Index of Public Utility Construction Costs - Section E2 - Cost Trends of Electric Utility Construction - South Atlantic Region for Total Distribution Plant for the average year the plant in FERC Account 364 was placed in-service versus the same index as of 2017.

For DEC's Account 364, the 2017 index is 674. The second index is more involved in that it requires the determination of the weighted average age of the Account 364 assets. As shown in the table below, the age of each vintage is determined by subtracting the vintage year from the base year of 2017 and adding 0.5. to produce a mid-year result. The weighted age is calculated by multiplying each vintage's cost by its age. The average weighted age is then computed by dividing the sum of the weighted ages by the sum of all the vintage costs which results in 18.86 years for Account 364 - Overhead Poles, Towers & Fixtures. The table below summarizes this calculation for selected years since the complete table for all years would contain excessive detail.

| Vintage | Cost | Age (2017 - vintage) + .5 | Weighting cost x age |
|---|---|---|---|
| 1960 | 4,940,355.15 | 57.5 | 284,070,421.13 |
| 1961 | 555,612.78 | 56.5 | 31,392,122.07 |
| 1962 | 1,096,448.21 | 55.5 | 60,852,875.66 |
| | | | |
| 2015 | 53,743,199.35 | 2.5 | 134,357,998.38 |
| 2016 | 59,784,449.03 | 1.5 | 89,676,673.55 |
| 2017 | 89,455,592.70 | 0.5 | 44,727,796.35 |
| | | | |
| Total | 1,312,791,934 | | 24,756,778,615.15 |
| Average Age | | | 18.86 |

The resulting weighted average age of 18.86 years is then rounded to 19 years and subtracted from 2017 to produce the date of July 1, 1998. Using this date in the Handy-Whitman index results in an average age index value of 298. Multiplying the 2017 Account 364 minimum cost per mile, $26,768, by the "de-escalation" factor, 298/674, results in a weighted average historical cost of $11,835 per mile. In turn, this value is multiplied by the miles of overhead lines, 48,998, to produce a minimum installed cost for Account 364 of $579,893,159.

With some variations, this process is repeated for FERC Accounts 365, 367 and 368. For example, Account 367 - Underground Conductors & Devices the miles of line value includes only underground lines. For Account 368 – Line Transformers, the miles of line value represents only primary lines as line transformers are not needed on secondary lines. In contrast, Account 366 – Underground Conduit is treated 100% as minimum system as underground conduit is not installed based on demand but rather by customer location. The attached Exhibit A provides a more detailed summary of DEC's minimum system calculation for all the relevant distribution-related FERC accounts.

In the cost-of-service study, the minimum system portion of these distribution accounts are allocated to customer classes based on the number of customers. The remainder of these accounts, less any direct assignments, are allocated using a non-coincident demand allocator.

While Duke Energy Progress(DEP) employed a slightly different approach to estimating the minimum system portion of its vintage distribution plant balances in FERC Accounts 364, 365, 367 and 368 in its most recent cost-of-service filings based on a historic 2010 study, it achieved a comparable result to the methodology described above. Since it is a less complex calculation, DEP plans to follow a similar approach to estimating minimum system costs in future cost-of-service studies as described above.

## VI. Whether or not the basic customer method of allocating costs should be adopted

The "basic customer" method classifies service-drops, meters, meter-reading and billing as customer-related costs while poles, wires and transformers are classified as demand-related. This concept's premise is that metering and billing costs do not vary based on usage or demand and thus are rightfully recovered in the monthly recurring charge. However, this approach does not recognize the utility's requirement to provide a basic amount of distribution facilities, including poles, line and transformers, to provide service to a customer with, say, just one 100-watt light bulb.

The “basic customer” method is, therefore, inconsistent with cost causation principles which are the bedrock of cost-of-service studies and ratemaking.

The “basic customer” approach promotes cross-subsidies among customers. For a residential class of customers with a fixed customer charge designed only to collect metering, billing and customer service costs, low usage customers will not be covering all the costs of the distribution system installed to connect and serve them. Thus, high usage customers will subsidize low usage customers through their bills. If the minimum system concept is employed, some of the distribution costs are recovered in the customer charge thereby lowering the remaining portion of the rate and reducing the subsidy.

This cross-subsidization is further aggravated because the majority of residential customers’ rates do not have a demand component, collecting all non-fixed costs through an energy rate. Duke is not aware of anyone that advocates that the Distribution system costs are driven by kwh usage or energy. The basic customer approach argues that more of the distribution costs should be functionalized as demand related vs. customer related. However, neither DEP or DEC currently has demand charges in its primary residential rate schedule. As a result, the demand related charges are often recovered through an energy rate. This leads to additional cross-subsidization.

## VII. Other options for allocating distribution costs as customer or demand-related, and other methods for setting the basic customer charge.

As described above, Duke Energy allocates distribution plant using number of customers and non-coincident demand allocators. There is an allocation method that allocates distribution plant using a weighted average of the non-coincident demand and the Individual Customer Maximum Demand(ICMD). ICMD is the total maximum demand of the individual customers in a specific distribution locale. Duke’s position is that all customers do not impose their maximum demand on the distribution system at the same time. Rather, individual customers will use their maximum demand at different times than other customers who are served by the same distribution facilities, and as a group, will have a non-coincident peak that is less than the group's ICMD. (For obvious reasons, this load diversity is higher the farther away the distribution equipment is from the customer.) Thus, Duke Energy "sizes" distribution equipment to meet this non-coincident peak.

One could argue that distribution costs are largely fixed and do not vary with load and therefore should entirely be included in the monthly customer charge. These arguments have been accepted in California and Nevada resulting in higher customer charges than seen in North Carolina.

A utility in New York filed a cost-of-service study that advocated distribution costs allocated 50% demand and 50% number of customers. This proposal was supported by the Commission staff in that state.

Other jurisdictions, such as Maine, have a basic customer charge which gives the customer up to 100 kWh of "free" energy in a month. It is interesting that Maine rejects the minimum system concept but permits a minimum amount of energy to be included with the customer charge regardless of customer usage.

## VIII. Recommendation of Duke Energy in support of Minimum System Concept

Duke Energy believes that "cost causation" is the foundation of cost-of-service studies. To that end, every customer requires some minimum amount of distribution facilities (wires, poles, transformers, etc.) to "access" the distribution system; and thus, every customer "causes" Duke Energy to install some basic amount of distribution equipment. The methodology Duke Energy uses to develop its minimum system is to determine what distribution facilities are required if customers require only some minimum level of usage, that is, a 100-watt light bulb. This minimum level of facilities ensures that electricity can be delivered to each customer when the customer chooses to use electricity. Without the use of the minimum system allocation methodology, low usage customers avoid paying for the distribution facilities necessary to provide service to them which is counter to cost causation principles.

Duke Energy firmly supports the use of the minimum system concept using the modified “minimum size” approach instead of the “zero intercept” method. While theoretically attractive, Duke Energy believes the “zero intercept” method requires more data and is computationally more complex while ultimately achieving a comparable result. Thus, Duke Energy believes the simpler modified “minimum size” method is the preferable approach for setting rates.

**DUKE ENERGY CAROLINAS**
MINIMUM SYSTEM - PROPOSED METHODOLOGY

**Exhibit A**

Minimum Cost per Unit
12 Months Ended December 31, 2017

| | 2017 Min Cost per Mile of Line | Average Age(Yrs) | 2017 Index | Index for Avg age | Adjusted Min Cost per Mile of Line | Miles of Line | Installed Minimum Cost $/Unit | Installed Minimum Cost Amount ($) | 2017 NC Plant Bal $000 | NC Direct Assign | Net | Min Sys As % of NC Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5)=(1)*(4)/(3) | (6) | (7)=(5) | (8)=(6)x(7) | (9) | (10) | (11)=(9)-(10) | (12)=(8)/1000/(11) |
| **Account 364 - OH Poles, Towers, & Fixtures** | | | | | | | | | | | | |
| | 26,768 | 18.86 | 674 | 298 | 11,835.11 | 48,997.70 | 11,835.11 | 579,893,159 | 1,124,607 | 104,076 | 1,020,531 | 56.8% |
| **Account 365 - OH Conductors & Devices** | | | | | | | | | | | | |
| | 34,197 | 15.19 | 674 | 322 | 16,337.44 | 48,997.70 | 16,337.44 | 800,496,943 | 1,568,968 | 38,352 | 1,530,616 | 52.3% |
| **Account 366 - Underground Conduit** | | | | | | | | | | | | |
| All minimun system after excluding directs | | | | | | | | 149,656,000 | 155,699 | 6,043 | 149,656 | 100.0% |
| **Account 367 - Underground Conduit & Devices** | | | | | | | | | | | | |
| | 34,792 | 16.01 | 674 | 313 | 16,157.03 | 29,415.40 | 16,157.03 | 475,265,563 | 1,480,378 | 62,280 | 1,418,098 | 33.5% |
| **Account 368 - Line Transformers** | | | | | | | | | | | | |
| | 13,839 | 18.24 | 674 | 297 | 6,098.27 | 57,814.89 | 6,098.27 | 352,570,767 | 1,029,210 | 43,095 | 986,115 | 35.8% |

| NC | Overhead | Underground |
|---|---|---|
| Primary | 38,013.27 | 19,801.62 |
| Secondary | 10,984.43 | 9,613.78 |
| | 48,997.70 | 29,415.40 |

**Notes:** (1) This exact approach was not used in the last DEC NC rate case nor in the 2017 NC DEC COSS. At that time, DEC did not offer underground service as a standard service. Thus, underground lines were treated the same as overhead lines for purposes of the minimum system calculation.

**Sources:**
(1) 2017 Costs Per Mile of Skeleton Plant - includes labor and materials
(2) Sum of each vintage cost times age in years for account divided by sum of all vintage costs for account
(3) Handy-Whitman Index of Public Utility Construction Costs - Section E2 - Cost Trends of Electric Utility Construction - South Atlantic Region for 2017 for Total Distribution Plant
(4) Handy-Whitman Index of Public Utility Construction Costs - Section E2 - Cost Trends of Electric Utility Construction - South Atlantic Region for 2017 for Total Distribution Plant
Acct 364 - 19 yrs July 1, 1998
Acct 365 - 15 yrs July 1, 2002
Acct 367 - 16 yrs July 1, 2001
Acct 368 - 18 yrs July 1, 1999
(6) DEC Line Mileage by State and Phase for Year End 2017

**North Carolina Distribution Model Responses for NCUC Public Staff-11/29/2018**

1. **Overview and Explanation of Current Methodology:** Dominion Energy North Carolina (DENC) currently employs a minimum-system distribution model to separate the customer and demand components of the electric distribution plant used in providing service to customers. This method is based on applying baseline material unit cost metrics and scaling these unit costs up to the size of the existing distribution system to calculate a minimum system component. Primary and secondary distribution plant assets are separated based on a combination of studies and sampling techniques to arrive at a percentage split between the two categories. Brief summaries are provided below:

    a. FERC Account 360 and 361: These accounts are ratioed between customer and demand, and between overhead and underground, on the basis of the customer and demand plant amounts for Accounts 364, 365, 366, and 367 (whose calculations are described below). Accounts 364 and 365 are overhead, and accounts 366 and 367 are underground. The percentages are then applied to the total balance for each account to arrive at customer overhead, customer underground, demand overhead, and demand underground amounts for FERC 360 and 361.
    b. FERC Account 364: The minimum system component for FERC Acct 364 is considered to be a 35' pole. The embedded historical unit cost of a 35' pole is calculated from existing mass item records. This per unit cost is then multiplied by the total number of existing poles, at primary level and secondary level, to arrive at the minimum system, or customer, portion of FERC Acct 364. The demand amount is computed as the customer amount subtracted from the account total.
    c. FERC Account 365: The minimum system component for FERC Acct 365 is considered to be 4/0 and under wire. The embedded historical unit cost of a pound of 4/0 and under wire is calculated. Using a pounds per foot estimate, this unit cost is then multiplied by the number of wire feet of conductor in the existing distribution system, at primary level and secondary level, to arrive at the minimum system, or customer, portion of FERC Acct 365. The demand amount is derived by subtracting the customer amount from the account total.
    d. FERC Accounts 366 and 367: The minimum system component for Account 367 is the cost of a #4 Primary Cable (for primary distribution) or a #8 Secondary Cable (for secondary distribution). Both prices are calculated via regression analysis. The present day unit cost of each type of cable is scaled to an estimated historical unit cost for the system using a reduction factor based on Handy-Whitman based survivor information. This unit cost is then multiplied by

primary circuit feet and secondary circuit feet respectively. The resulting values then form the respective basis customer amounts for primary and secondary booked cost of cable. These figures are subtracted from the primary and secondary subtotals of the booked cost of cable to arrive at the primary and secondary demand portion of FERC 367. The percentages derived in FERC 367 calculations are then applied to the FERC 366 Underground Conduit account.

e. <u>FERC Account 368:</u> The minimum system component is valued as the average cost of the transformer zero intercept. This unit cost is multiplied by the total number of transformers to arrive at the minimum system, or customer, portion of the account. The customer amount is then subtracted from the total booked cost of line transformers to arrive at the demand amount.

f. <u>FERC Account 369:</u> FERC Account 369 is calculated separately for overhead and underground service drops. The minimum system component for overhead service an 80 foot #2 aluminum service. The present day cost of this service is scaled to an estimated historical unit cost using a reduction factor based on Handy-Whitman based survivor information. This unit cost is multiplied by the total number of overhead customers to arrive at the minimum system, or customer, portion of the account. The minimum system component for underground service is a #8 service, from the pad to facility and from the pole to facility, each calculated via regression analysis. These present day unit costs are scaled to an estimated historical unit cost using a reduction factor based on Handy-Whitman based survivor information. These unit costs are multiplied by the total numbers of underground customers receiving service either from pad to facility or pole to facility to arrive at the minimum system, or customer, portion of the account. The customer amount is then subtracted from the total account to arrive at the demand amount.

g. <u>FERC Account 370-373:</u> These accounts are being classified as customer related. FERC account 370 is assigned as much as possible to each individual customer and the remainder of 370 metering charges is allocated based on the factors relevant to each class. FERC 373 is unique and represents the cost allocated by unit numbers of street lights.

2. **<u>History of the Use of Minimum-System</u>:** The minimum-system distribution plant cost allocation has been used by DENC since the June 28, 1973 Docket No. E-7, SUB 141 order was promulgated by the Commission. This order specified a detailed minimum-size, minimum-system methodology as follows:

> *(7) That VEPCO shall complete and file with the Commission annually on April 30 a Cost of Service Study detailing the rate of return earned by each class of service,*

*and the customer, demand and energy components of revenue deductions and net plant investment, and allowance for working capital; that such studies shall be based upon each calendar year's operations; that demand data used shall have been taken within two years of the end of the period under study; that the methods of execution of cost of service studies shall be determined by the Company with the goals of accuracy, responsible allocation, and stability over time; and that studies based upon alternative methods may be submitted for consideration, but that at least one shall be based upon the following:*

i. *(a) Sizes of distribution plant used in computation of customer components shall be the minimum sizes which will meet the requirements of the National Electrical Safety Code and other like restrictions, and costs for such sizes of equipment shall be actual costs, if available, or shall be computed using statistical regression techniques and the minimum-intercept method.*
ii. *(b) Coincident demands shall be measured at the time of daily system peaks, and that demand data taken at the time of the top five daily system peaks (if all five are within 1/2% of the yearly system peak) shall be averaged to calculate the coincident demand factors to assure proper assignment of coincident peak responsibility.*
iii. *(c) The distribution line portion of Account 360, Land and Land Rights, shall be allocated on customers only.*
iv. *(d) Account 364 - Poles, Towers, and Fixtures, shall be allocated to primary and secondary based upon the number of wires on each pole in the sample, weighted by the relative difference in wire sizes, and all neutrals shall be allocated to the primary, that if poles are initially installed oversized to carry planned later wire additions, the final design shall, if possible, be used in the above allocation, and that the Minimum Intercept cost of a Class 7 pole shall be used when computing the customer component.*
v. *(e) The calculation of the customer component of Account 365 - Conductors, shall be based upon two-wire secondaries and primaries and three-wire joint secondary\primary lines, and that the Minimum Intercept cost of #4 ACSR or equivalent shall be used.*
vi. *(f) The calculation. of the customer component of Account 367 - Underground Conductors and Devices, shall be based upon #4 Al UG cable primary and #10 Cu or #8 AI duplex 600 V UG cable (or such cable as to carry a minimum load) for secondaries.*
vii. *(g) The calculation of the customer component of Account 368 - Transformers, shall be based upon a 0 KVA Minimum Intercept.*

viii. *(h) The calculation of the customer component of Account 369 - Services, shall be based upon #4 EC, #ACSR, #I0 AD Cu., or #12 MHO Cu for overhead services and #I0 Cu or #8 AI duplex 600 volt UG cable for underground.*

This methodology has been utilized with some deviation from the exact materials but conforming to the general principle and method to present date by DENC. The current undertaking provides an ideal opportunity to revisit and refine the process.

3. **<u>History of Allocation of Distribution Costs as "demand-related" and "customer-related"</u>:** The history of allocation of these components is described above in detail and is currently implemented as ordered by previous Commission rulings.

4. **<u>Explain the Company's current allocation of distribution costs and why it is appropriate</u>:** The Company develops a set of factors to allocate customer-related costs and demand-related costs to the relevant customer classes. These factors are derived based on number of customers in each class at each service level, non-coincident demands, and class peak demands in each class at each service level respectively. The amounts derived in the distribution model are multiplied by the factors for each class and account to arrive at the class amount for that item.

5. **<u>Whether or not the Basic Customer Method of Allocating Costs Be Adopted</u>:** The Basic Customer Method has not been specifically defined by the Public Staff; however, DENC understands this method to mean treating as customer costs all costs for distribution equipment installed directly on customer premises (meaning FERC Accounts 369 – Services, 370 – Metering, 371 – Installations on Customer Premises, and 373 – Street and Traffic Signals). Other distribution FERC accounts (360 – Land, 361 – Structures, 362 – Substations, 363 – Storage Battery Equipment, 364 – Poles, 365 – Overhead Conductors and Devices, 366 – Underground Conduit, 367 – Underground Conductors and Devices, and 368 – Transformers) would then be treated as demand related components.

   DENC does not advocate adopting the Basic Customer method. DENC has concerns regarding two major aspects of the Basic Customer method. The first concern is that, in theory, such a methodology does not appear to accurately reflect the design and use of the distribution system. As DENC understands it, the Basic Customer method argues that only a service and metering are necessary to set up a new customer; any poles and conductors, as well as transformers and substations, are only necessary if that customer were to take electric service (have some level of demand). Yet, by the same logic that conductors, poles, and transformers are unnecessary until demand exists, a meter and a service would be equally unnecessary, as the Company would have no need to meter if there was no electricity being provided, nor would a service drop serve any point if it were not connected to the distribution system. Furthermore, there is an element of demand cost even in Services and Metering, since a larger meter and larger service hookup would likely be needed for a customer expected to have a high demand, compared to a customer that would have low demand/usage. Thus, there does not seem to be a pure distinction between the two in terms of Customer and Demand function.

The Basic Customer method could also be interpreted as distinguishing between facilities solely installed to serve the single customer as opposed to facilities that are shared, but again, there is not such a clear distinction between the accounts as the Basic Customer method supposes. While most distribution poles, conductors, and transformers may be serving multiple customers, there are undoubtedly some locations within the distribution system where a single customer is the only one using certain poles, conductors, and transformers. For example, a relatively isolated rural residential customer at the end of the line may require multiple poles and additional feet of conductor to receive service on their property. As another example, a larger industrial customer might have its own transformer installed and could even have its own substation. Even a first customer in a new shopping development or residential neighborhood would require these "shared facilities" to be installed. While perhaps the sizing of the poles, conductors, and transformers that are installed may vary depending on the anticipated overall demand for the neighborhood or the development, the existence of a single customer requires the installation of poles, conductors, and transformers. Thus, while there is certainly a demand component to those items, the fact that they are shared facilities does not negate that the existence of a single customer requires the install of these facilities, regardless of whether other customers exist to share the facilities.

Furthermore, the concept of shared facilities must necessarily be limited by other factors, such as geography. The nature of distribution facilities is such that they serve much more localized areas than a generation plant or even transmission line, and as such, new customers in a new area would require additional facilities, even if such customers don't add enough demand to the overall system to strain the overall demand capacity of the distribution system. Thus, there is not just a pure demand element to these facilities; there are other considerations and requirements of the distribution system that extend beyond merely satisfying the total demand.

The second objection to the Basic Customer method is that the method is somewhat detached from the relevant ratemaking process. In cost based ratemaking, there are three general types of costs: fixed cost necessary to provide service to the customer, fixed cost necessary to serve the demand of the system, and variable costs dependent on energy. The first (customer costs) are not at all variable. The second (demand costs) are variable over a longer period of time but are fixed in the short term. And the third (energy costs) are variable in the short term as well as long term. With regards to the distribution system, the majority of costs are either customer or demand (there are some energy related costs related to efficient system design and limitation of line losses, as noted in the 1992 NARUC manual). In order to design accurate and appropriate rates based on cost causation, the rates should match the type of cost causation; fixed customer costs should be recovered through a fixed monthly customer charge, demand related costs should be recovered through a peak demand charge, and energy costs should be recovered through an energy related charge. Due to the limitations of current metering plant, most residential and small commercial customers do not have meters that can provide accurate kW demand readings, so a demand charge for residential customers is not currently feasible. Thus, the issue becomes whether it is more appropriate to recover the demand charges through a fixed monthly charge or through an energy charge.

DENC argues that a fixed monthly charge is more appropriate for two reasons. First, as demonstrated above, there are some aspects of distribution plant that are comingled between customer and demand to the point of being inseparable. As these costs cannot be clearly separated between demand and customer, and because a demand charge is not currently feasible, DENC argues that a customer charge is better reflects the costs incurred. Second, DENC notes that there are a number of situations where, if an energy based charge were implemented, a customer may be able to avoid paying for the distribution costs that they cause to be incurred. For example, a Christmas Lighting Store that is only open in November and December would require the same distribution equipment to meet its peak demand as a neighboring store that is open year round, because the facilities that are built must be built to serve the demand on the system and cannot be removed during the intervening months when they are not used, especially if they will be used again the next November & December. Yet, the Christmas Lighting Store customer would be able to avoid paying for its full portion of distribution system if there were an energy charge, since their overall energy usage over the year would not match their demand. As another example, a residential customer who has installed solar panels on her roof would still require the distribution system necessary to serve her load in the event she did not have functioning solar production, as it would be anticipated that at night or on cloudy days, the Company would need to serve the full demand. The distribution system required would be a combination of demand and customer related costs, but if the costs are recovered through an energy charge, this residential customer would avoid paying in proportion with the costs she is causing to be incurred, as the solar generation would offset energy consumption at other periods other than the period of peak demand. Thus, the residential customer with solar would avoid costs that she caused to be incurred, and other residential customers would end up subsidizing these costs. With the growth of distributed generation, the solar customer example is especially relevant in North Carolina.

Based on the above, DENC believes that the "Basic Customer" method does not adequately reflect the actual cost causation of the distribution system, nor does it result in rates that fairly recover costs on the basis of their incurrence.

6. **<u>Other Options for Allocating Distribution Costs as Customer or Demand-Related</u>:** Dominion Energy has been investigating an alternative methodology for determining customer and demand portions of distribution plant, which DENC is calling the "Average Load Duration Curve Method." This involves taking a new perspective on just what the intent of the Customer/Demand split represents in a Distribution Model FERC Account.

   Traditionally, a good deal of effort is spent in debate trying to determine the "value" of a minimum amount of FERC Account Plant that attempts to estimate the needs of a hypothetical customer with barest minimum electrical use. The current method faces further complications for accounts where present day unit costs need to be scaled back to estimated historical unit costs. Once this effort determines a Customer cost component for the FERC Account under review, this Customer component is subtracted from the total FERC Account value. This difference determines the Demand cost component for that FERC Account. Then there are further break downs based on separately derived customer class allocation factors (based on the number of customers at primary and secondary voltage levels) and demand class allocation factors (based on class peak demands or non-coincident peak demands at primary and secondary voltage levels).

   With new data collection methods and tools available to the utility, alternatives based on less theoretical frameworks are now available to help with this analysis. With its current load research software, DENC now has the ability to produce a Load Duration Curve for any defined group of customers. A Daily Load Duration Curve provides a wealth of information at a glance. The demand is graphed for every hour of the year. These curves thus produce the class maximum load, minimum load, and average load as well as the class load factor.

   DENC's distribution system has developed and refined over many years, and the design of the system continues to be evaluated to best serve the needs of the Company's customers and the usage profile of the system. DENC's distribution system thus requires much more detail and refinement than a hypothetical or theoretical system designed to carry a minimum load as many of the theoretical methods such as "Minimum System" or "Basic Customer". The system is cycled daily in real time to a maximum load and then to a minimum load. On winter days, this type of cycling may occur more than once.

   Therefore, an argument can be made that it makes the most sense to use actual field data to determine the Customer/Demand split of Distribution Plant FERC Accounts. The hourly data is available for every day of the year. This means there are a maximum peak and a minimum peak value for each day. Under the "Average Load Duration Curve Method", the actual field data for these daily maximums and minimums is used to determine the ratio between the average of the maximums and the average of the minimums. Such a method would be appropriate given that the distribution system is designed to deal with Non-Coincident Demands, and the customer component could then be treated as each customer's minimum demand, rather than the system total minimum demand. Using the average of daily minimums over the course of the year would thus more accurately capture each customer's minimum demand. Thus, the ratio of minimum demand to maximum demand represents the percent of the total FERC Account that should be designated as the customer portion. Then, as with other methods, the demand portion of the cost is the difference between customer and total. Now that each Distribution System FERC Account is split into the Customer/Demand components, then the further break down is accomplished with the Customer and Peak Demand allocation factors. A spreadsheet is attached that illustrates this straight-forward and consistent methodology.

There are a number of potential advantages to the "Average Load Duration Curve Method". This method is based on current and actual system data. The method is consistent and replicable and also reflects the realities of DENC's actual system. Based on DENC's initial investigation, it appears this method would not be subject to large fluctuations from year to year, so there would be similar or even greater stability compared to other methods. If applied by other utilities, the methodology could remain the same but would also reflect the differences in their distribution systems and load profiles. The method also simplifies the calculation of customer and demand plant, reducing the required inputs and the complications of updating and revising those as technology and system requirements change.

Aside from the method described in the preceding section, the NARUC Cost of Service manual specifically defines a method that it describes as, "Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer." (National Association of Regulatory Utility Commissioners, 1992, p. 90) This is the method primarily utilized by the Company. The other method is what in modern parlance is described as the zero-intercept method. NARUC describes this method as, "The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept." (National Association of Regulatory Utility Commissioners, 1992, p. 92) This method is only used by the Company for FERC account 368 as required in the 1973 order where it states, "the calculation of the customer component of Account 368-Transformers, shall be based upon a 0KVA Minimum intercept." (In the Matter of Application of Virginia Electric and Power Company for Authority to Increase its Electric Rates and Charges, 1973, p. 46) There are significant data availability limitations that restrict the practical use of the zero-intercept model on a broad basis to model distribution plant customer-related costs.

DENC is also currently working to refine and improve the quantification of the minimum-size, minimum-system approach, with two primary foci. First, computerized Distribution plant records can now be used to identify primary and secondary distribution plant in the field, and this information will be incorporated to determine the primary and secondary percent splits for the relevant accounts. Second, updated estimates of minimum materials costs and labor costs to install a minimum-size, minimum-system, with some consideration of today's minimum standards, are being reviewed. These efforts are in development, but when viewed from the perspective of the current case, some update to reflect technological and data availability changes since 1973 is necessary.

DENC also notes that DEC has proposed, in this proceeding, to use a "cost-per-mile of skeleton plant" method that makes use of the minimum-system concept but adopts a different approach to determining the customer component from the DENC order and appears to involve novel elements when compared with previous approved methodologies. This is an intriguing method that has a significant number of detailed engineering estimates and design parameters that requires more study by the Company prior to arriving at a conclusion as to its appropriateness for the fair recovery of distribution-related costs by DENC.

7. **Company's Recommendation:** The Company is prepared to continue use of the minimum-system methodology to derive the customer component of distribution-related costs. The minimum-system method is admittedly imperfect, as any methodology would be; however, it has significant historical precedent and consistency. Additionally, the basic theory underlying the minimum-system methodology is more consistent with the realities of the distribution system, as compared to methods such as the "Basic Customer" method. Furthermore, while the minimum-system method is data-intensive in terms of developing appropriate unit cost baselines, the minimum-system method has better data availability than methods such as the "Zero-Intercept" method.

   DENC is actively engaged in and undertaking an effort to modernize the specific manner in which the minimum-system concept is applied to individual accounts within the distribution model. This effort includes working to develop augmented data collection and analysis frameworks as well as reviewing and assessing other proposals such as the "cost-per-mile of skeleton plant" method being used by DEC in the current proceeding. Such evaluations and updates will further increase the accuracy of the minimum-system method, creating a better definition of customer and demand components of DENC's existing distribution system.

The Company is also encouraged by and actively investigating the "Average Load Duration Curve Method" described above and sees this as a potential way to arrive at a reasonable, fair, and consistent determination of customer and demand-related costs going forward. Not only does this method derive the relevant customer component and demand component for the distribution plant assets objectively based on empirical data analysis, but also the resulting outcome is based on a sample of tens of thousands of hours of load data from the distribution system as it exists serving customers. The data that forms the basis of this method is real to the existing distribution system, is measurable and can be recreated, and is based on actual distribution service provided to ratepayers. The sample data provided by DENC also includes multiple years with winter and summer peaks. To this point in its evaluation of the "Average Load Duration Curve Method", DENC has found that the method results in a robust and consistent analysis that reduces subjectivity and volatility in customer component computation and allocation. DENC would recommend further evaluation of this method.

8. **Appendix A-Detailed Walkthrough of FERC 364 Calculation:** The below summary was provided to Public Staff as part of the 9/11/18 meeting. A copy of the Distribution Model spreadsheet provided at the same meeting is also attached.

> Our current spreadsheet tab "A" has three sections to it. The middle section actually involves most of the input data. For Account 364, we pull in the number of total poles in North Carolina, which comes from our Fixed Asset Accounting group's Mass Item file. We also take the specific number of 35' poles in North Carolina and the total booked cost associated with the 35' poles from that Mass Item file. Note that the booked cost is based on cost at the time of installation, and thus we are using an historic, as installed, amount for those poles rather than looking at the cost of currently installing them today.
>
> Using the average cost of a 35' pole, which is assumed to be minimum system, and the total number of poles, we can calculate the minimum system, or customer, component of Account 364. Taking the total dollars in the account, we then calculate the demand component of Account 364 as the total amount less the customer amount.
>
> We also divide the distribution system between Primary level and Secondary level components. For Account 364, we use the results of a pole sampling survey to determine an approximate percentage of primary and secondary poles (both for the account in total and for the specific customer related poles) and divide the customer and the total account between primary and secondary, and then again calculate the demand component by removing the customer component from the total.

Using these numbers, we create a set of three ratios for Account 364. These are Primary to Total Account, Primary Customer to Primary Total, and Secondary Customer to Secondary Total. As we now use the UI Cost of Service Program to handle our Cost of Service, we take these ratios and allocate the Account 364 plant balance from our Plant in Service template into our 4 North Carolina Acct 364 Distribution Plant lines that appear on our Schedule 10: Primary - Customer, Primary - Demand, Secondary - Customer, and Secondary - Demand. This is done on the Dist Plant Work Sheet tab. From there, the numbers go to the UI Distribution Outputs tab, where they are organized in a way that allows us to easily paste them into the UI System.

## References

In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable for Electric Service in North Carolina, Docket No. E-7, Sub 1146 (North Carolina Utilites Commission June 22, 2018).

In the Matter of Application of Virginia Electric and Power Company for Authority to Increase its Electric Rates and Charges, Docket No. E-22, Sub 141 (North Carolina Utilites Commission June 28, 1973).

National Association of Regulatory Utility Commissioners. (1992). *Electric Utility Cost Allocation Manual.* Washington, DC: National Association of Regulatory Utility Commissioners.

[illegible]

HE COS O #4 R MAR IS COM U ED HIS COS S HEN RENDED BACK O HE AVERAGE AGE O AN US NG A SURVIVOR CHAR AND HE HAND -WHI MAN NDEX HE SAME ROCESS S O OWED OR SECONDAR US NG HE COS O 500mcm AND 4 0 CAB E O DE ERM NE HE COS O #8 SECONDAR CAB E

R MAR

S O E = (COS 00KCM - COS 0) S ZE 00KCM - S ZE 0)
COS #4 = S O E * SIZE #4) - ((S O E * S ZE 0) - COS 0)
UNI RICE = COS #4 000 * HAND -WHI MAN RA O

| | | |
|---|---|---|
| S O E = | 0 02884009 | $32 88 -$7 083) ( 000000- 05500) |
| COS #4 = | $5 244 | 0 0288 009*4 740 -( 0 02884 09* 05500 -$7 083) |
| UNI R CE = | $3 50037000 | ($5 244 0 0)*0 6700) |

0 0 2037854

SECONDAR 3042 629495

S O E = (COS 5 0KCM - COS 4 0) S ZE 500KCM - S ZE 4 0) 7083
COS #8 = S O E * SIZE #8) - ((S O E * S ZE 4 0) - COS 4 0) -4040 370505
UNI RICE = COS #4 000 * HAND -WHI MAN RA O 4040 382543

| | | |
|---|---|---|
| S O E = | 0 005072 8 | $7 047 $5 84) (500000 2 600) |
| COS #8 = | $4 595 | 0 0050 2 8* 65 0 -( 0 005072 8*2 600 -$5 584) |
| UNI R CE = | $3 067 6250 | ($4 595 0 0)*0 6700) |

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| | NE RANS ORMERS | CO BA ANCE | CO 2 NUMBER O RANS ORMERS ( ROM MEMOS) | CO 3 AVERAGE COS O RANS ORMER ZERO N ERCE | CO 4 CUS OMER COM ONEN CO 2 * CO 3) | CO 5 DEMAND COM ONEN (CO - CO 4) |
|---|---|---|---|---|---|---|
| | RANS ACCOUN 368 5 | $64 26 366 | 7 862 | $ 60 43 | $9 282 80 | $ 4 843 565 |
| | NDUS RIA RANS ORMERS | | | | | |
| 2 | RANS ORMERS ACCOUN 368 2 | $5 700 798 | 235 | $ 60 43 | $37 70 | $5 663 097 |
| | CA ACI ORS | | | | | |
| 3 | CA ACI ORS ACCOUN 3 8 3 4 | $7 7 278 | | | | $7 7 278 |
| 4 | O A ACCOUN 368 | $70 544 442 | | | | |
| 5 | RESA E | $ 87 297 | 7 | $ 60 43 | $2 727 | $ 84 570 |
| 6 | ACCOUN 3 8 ESS RESA E | $70 357 45 | | | $9 3 7 775 | $6 039 370 |

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REGRESSION ANA SIS O DE ERM NE HE COS O CAB E

ENG NEERING ES IMA ES ROV DE HE RESEN DA COS O NS A 500mcm AND 4 0 SERVICE CAB E US NG REGRRESS ON ANA S S BASED ON HESE COS S HE COS O #8 SERV CE IS COM U ED HIS COS S HEN RENDED BACK O HE AVERAGE AGE O AN US NG A SURVIVOR CHAR AND HE HAND -WHI MAN NDEX

AD O HOUSE

S O E = (COS 5 0KCM - COS 4 0) S ZE 500MCM - SIZE 4 0)
COS #8 = S O E * SIZE #8) - ((S O E * S ZE 4 0) - COS 4 0)
UNI RICE = COS #8 000 * HAND -WHI MAN RA O

| | |
|---|---|
| S O E = | 0 000839 |
| COS #4 = | $602 |
| UNI R CE = | $463 3594 |

SECONDAR

S O E = (COS 5 0KCM - COS 4 0) S ZE 500KCM - S ZE 4 0)
COS #8 = S O E * SIZE #8) - ((S O E * S ZE 4 0) - COS 4 0)
UNI RICE = COS #4 000 * HAND -WHI MAN RA O

| | |
|---|---|
| S O E = | 0 00 447 2 |
| COS #8 = | $723 |
| UNI R CE = | $556 493 |

I

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V

| | OVERHEAD | NUMBER O CUS OMERS | UNI COS | O A COS |
|---|---|---|---|---|
| | CUS OMER OR ON | 53 085 | $62 08 | $3 295 729 |
| 2 | DEMAND ( NE 4 - NE 2) | | | $ 803 40 |
| 3 | O A ACCOUN 369 | | | $ 5 099 30 |

| | UNDERGROUND | NUMBER O CUS OMERS | UNI COS | O A COS |
|---|---|---|---|---|
| 4 | CUS OMER ( AD O HOUSE) | 6 426 | $ 63 36 | $7 6 42 |
| 5 | CUS OMER ( O E O HOUSE) | 50 839 | $ 56 49 | $28 29 553 |
| 6 | DEMAND ( NE 7 - NE 4 & 5) | | | $32 95 08 |
| 7 | O A ACCOUN 369 2 3 4 & 5 | | | $68 097 776 |
| 8 | O A ACCOUN 369 | | | $83 96 906 |

OVERHEAD SERV CE - HE RESEN DA COS O NS A NG A #4 SERV CE DRO IS RENDED BACK O HE AVERAGE AGE O AN US NG A SURV VOR CHAR AND HE HAND -WHI MAN INDEX

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|---|---|
| 360.36 ~agp | VA ACCOUN 360 6 |
| NC3 0 36 ~agp | NC ACCOUN 60 36 |
| om 20~g | change e t ma in to cente ema n ng pages |
| 364~agp | VA ACCOUN 364 |
| 365~agp | VA ACCOUN 365 |
| 366~agp | VA ACCOUN 366 |
| 367~agp | VA ACCOUN 367 |
| 368~agp | VA ACCOUN 369 |
| 369~agp | VA ACCOUN 369 |
| VA370~agp | VA ACCOUN 370 |
| VAGS370~agp | VA ACCOUN 370-GS |
| 373~agp | VA ACCOUN 373 |
| NC3 4~ gp | NC ACCOUN 64 |
| NC3 5~ gp | NC ACCOUN 65 |
| NC3 5A~agp | NC ACCOUN 65 O E W RE SAM E RIMAR |
| NC3 5B~agp | NC ACCOUN 65 O E W RE SAM E SECONDAR |
| NC3 5C~agp | NC ACCOUN 65 O E W RE SAM E AD US MEN S |
| NC3 6~ gp | NC ACCOUN 66 |
| NC3 7~ gp | NC ACCOUN 67 |
| NC3 7A~agp | NC ACCOUN 67 REGRESS ON ANA S S |
| NC3 8~ gp | NC ACCOUN 68 |
| NC3 9~ gp | NC ACCOUN 69 |
| NC3 9A~agp | NC ACCOUN 69 REGRESS ON ANA S S |
| NC3 0~ gp | NC ACCOUN 70 |
| N U AREA~agp | IN U AREA OR D S R BU ON MODE |
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## REALLOCATION OF ACCOUNTS 360 (LAND) AND 361 (STRUCTURES)
## DECEMBER 31, 2017

| | | ACCOUNT 364 POLES | ACOUNT 365 OH COND | ACCOUNT 366 CONDUITS | ACCOUNT 367 UG COND | ACCOUNT 368 TRANS | TOTAL | % | |
|---|---|---|---|---|---|---|---|---|---|
| PRIMARY-OH | CUSTOMER | 168,104,088 | 101,933,101 | | | | 270,037,189 | 4.1536% | V60POC |
| PRIMARY-OH | DEMAND | 244,710,759 | 536,278,192 | | | | 780,988,951 | 12.0127% | V60POD |
| SECONDARY-OH | CUSTOMER | 152,618,449 | 87,159,892 | | | | 239,778,341 | 3.6881% | V60SOC |
| SECONDARY-OH | DEMAND | 222,168,852 | 625,585,815 | | | | 847,754,667 | 13.0397% | V60SOD |
| UNDERGROUND | CUSTOMER | | | 51,816,046 | 355,603,086 | | 407,419,132 | 6.2667% | V60UC |
| UNDERGROUND | DEMAND | | | 310,277,900 | 2,129,374,791 | | 2,439,652,691 | 37.5253% | V60UD |
| TRANSFORMERS | CUSTOMER | | | | | 117,727,399 | 117,727,399 | 1.8108% | V60TC |
| TRANSFORMERS | DEMAND | | | | | 1,397,989,731 | 1,397,989,731 | 21.5031% | V60TD |
| | | 787,602,148 | 1,350,957,000 | 362,093,946 | 2,484,977,877 | 1,515,717,130 | 6,501,348,101 | 100.0000% | |

### ACCOUNT 360 - LAND AND LAND RIGHTS

| | | % | VA JUR |
|---|---|---|---|
| PRIMARY-OH | CUSTOMER | 4.1536% | 1,206,404 |
| PRIMARY-OH | DEMAND | 12.0127% | 3,489,105 |
| SECONDARY-OH | CUSTOMER | 3.6881% | 1,071,221 |
| SECONDARY-OH | DEMAND | 13.0397% | 3,787,384 |
| UNDERGROUND | CUSTOMER | 6.2667% | 1,820,164 |
| UNDERGROUND | DEMAND | 37.5253% | 10,899,265 |
| TRANSFORMERS | CUSTOMER | 1.8108% | 525,953 |
| TRANSFORMERS | DEMAND | 21.5031% | 6,245,586 |
| TOTAL VA-ACCT 360 | | | 67,296,011 |
| LESS: SUBSTATION RELATED | | | 38,250,928 |
| ALLOCATED PORTION-360 | | | 29,045,083 |

### ACCOUNT 361 -STRUCTURES AND IMPROVEMENTS

| | | % | VA JUR |
|---|---|---|---|
| PRIMARY-OH | CUSTOMER | 4.1536% | 96,244 |
| PRIMARY-OH | DEMAND | 12.0127% | 278,351 |
| SECONDARY-OH | CUSTOMER | 3.6881% | 85,459 |
| SECONDARY-OH | DEMAND | 13.0397% | 302,147 |
| UNDERGROUND | CUSTOMER | 6.2667% | 145,208 |
| UNDERGROUND | DEMAND | 37.5253% | 869,513 |
| TRANSFORMERS | CUSTOMER | 1.8108% | 41,959 |
| TRANSFORMERS | DEMAND | 21.5031% | 498,256 |
| TOTAL VA-ACCT 361 | | | 78,501,903 |
| LESS: SUBSTATION RELATED | | | 76,184,766 |
| ALLOCATED PORTION-361 | | | 2,317,137 |
| CUSTOMER | | | 15.9192% |
| DEMAND | | | 84.0808% |

| December | Distribution Plant - End of Period 2017 | Less Ringfenced Amounts | Distribution Plant - End of Period 2017 | | |
|---|---|---|---|---|---|
| FERC Acct 360.0 NC | 1,892,017 | | 1,892,017 | | |
| FERC Acct 360.0 NC Substation | 976,766 | | 976,766 | | |
| FERC Acct 360.0 Va | 29,045,083 | | 29,045,083 | | |
| FERC Acct 360.0 Va Substation | 38,250,928 | | 38,250,928 | 70,164,794 | 360 |
| FERC Acct 361.0 NC | - | | - | | |
| FERC Acct 361.0 NC Substation | 8,196,703 | | 8,196,703 | | |
| FERC Acct 361.0 Va | 2,317,137 | | 2,317,137 | | |
| FERC Acct 361.0 Va Substation | 76,184,766 | | 76,184,766 | 86,698,606 | 361 |
| FERC Acct 362.0 NC | 84,706,202 | 491,877 | 84,214,325 | | |
| FERC Acct 362.0 Va | 1,232,113,055 | 598,925 | 1,231,514,130 | | |
| FERC Acct 362.0 North Anna | - | | - | 1,315,728,456 | 362 |
| FERC Acct 364.0 NC | 77,404,210 | | 77,404,210 | | |
| FERC Acct 364.0 Va | 794,017,873 | 1,222,328 | 792,795,545 | 870,199,755 | 364 |
| FERC Acct 365.0 NC | 102,846,731 | | 102,846,731 | | |
| FERC Acct 365.0 Va | 1,374,456,401 | | 1,374,456,401 | 1,477,303,132 | 365 |
| FERC Acct 366.1 NC | 6,779,399 | | 6,779,399 | | |
| FERC Acct 366.1 Va | 362,176,090 | | 362,176,090 | 368,955,489 | 366 |
| FERC Acct 367.0 NC | 105,093,290 | | 105,093,290 | | |
| FERC Acct 367.0 Va | 2,486,501,703 | | 2,486,501,703 | 2,591,594,993 | 367 |
| FERC Acct 368.1 NC | 70,544,442 | | 70,544,442 | | |
| FERC Acct 368.1 Va | 1,518,150,230 | | 1,518,150,230 | | |
| FERC Acct 368.0 North Anna | - | | - | 1,588,694,672 | 368 |
| FERC Acct 369.1 NC | 15,099,130 | | 15,099,130 | | |
| FERC Acct 369.1 Va | 107,572,970 | | 107,572,970 | | |
| FERC Acct 369.2-5 NC | 68,097,776 | | 68,097,776 | | |
| FERC Acct 369.2-5 Va | 1,314,989,765 | | 1,314,989,765 | 1,505,759,641 | 369 |
| FERC Acct 370.0 NC | 13,726,957 | | 13,726,957 | | |
| FERC Acct 370.0 Va | 510,358,444 | | 510,358,444 | 524,085,401 | 370 |
| FERC Acct 371.0 NC | 713,072 | | 713,072 | | |
| FERC Acct 371.0 NC - C1 NC | 886,158 | | 886,158 | | |
| FERC Acct 371.0 NC - C2 NC | - | | - | | |
| FERC Acct 371.0 Va | 2,854,243 | | 2,854,243 | | |
| FERC Acct 371.)Va - C1 VA | 18,568,786 | | 18,568,786 | | |
| FERC Acct 371.)Va - C2 VA | - | | - | 23,022,259 | 371 |
| FERC Acct 373.0 NC | 19,461,788 | | 19,461,788 | | |
| FERC Acct 373.0 Va | 338,110,722 | | 338,110,722 | 357,572,510 | 373 |
| ARO Asset - Decommissioning | - | | - | | |
| Sales and Use Tax Contra Asset - I | (18,723,156) | | (18,723,156) | | |
| ARO Asset - Non-Decommissioninç | - | | - | | |
| FERC 1030 Experimental Plant | 917,006 | | 917,006 | | |
| | 10,764,286,687 | 2,313,129 | 10,761,973,557 | | |

**End of Period 2017**

| | | |
|---|---|---|
| **FERC Acc. 360 - Land & Land Rights** | | |
| 360 - VA-NON-PVT MILITARY | **0** | 0 |
| 360 - VA - FERC | **314,712** | |
| 360 - NC - FERC | **100,844** | |
| **FERC Acc. 361 - Structures & Improvements** | | |
| 361 - VA-NON-PVT MILITARY | **0** | 0 |
| 361 - VA - FERC | **1,471,729** | |
| 361 - NC - FERC | **1,010,567** | |
| **FERC Acc. 362 - Station Equipment** | | |
| 362 - VA-NON-PVT MILITARY | **$2,081,151** | 2,081,151 |
| 362 - VA - FERC | **24,614,255** | |
| 362 - NC - FERC | **11,411,104** | |
| **FERC Acc. 364 - Poles, Towers & Fixtures** | | |
| 364 - VA-NON-PVT MILITARY | **$3,164,042** | 3,164,042 |
| 364 - VA - FERC | **3,251,683** | |
| 364 - NC - FERC | **933,778** | |
| **FERC Acc. 365 - O. H. Conductors & Devices** | | |

| | | |
|---|---|---|
| 365 - VA-NON-PVT MILITARY | $8,318,451 | 8,318,451 |
| 365 - VA - FERC | 15,180,950 | |
| 365 - NC - FERC | 4,095,633 | |
| **FERC Acc. 366 - Underground Conduit** | | |
| 366 - VA-NON-PVT MILITARY | $997,382 | 997,382 |
| 366 - VA - FERC | $0 | |
| 366 - NC - FERC | $0 | |
| **FERC Acc. 367 - Underground Conductors & Devices** | | |
| 367 - VA-NON-PVT MILITARY | $17,814,123 | 17,814,123 |
| 367 - VA - FERC | 833,897 | |
| 367 - NC - FERC | 856,753 | |
| **FERC Acc. 368 - Line Transformers** | | |
| 368 - VA-NON-PVT MILITARY | $2,615,556 | 2,615,556 |
| 368 - VA - FERC | 1,811,913 | |
| 368 - NC - FERC | 187,297 | |
| **FERC Acc. 369 - Services** | | |
| 369 - VA-NON-PVT MILITARY | $696,232 | 696,232 |
| 369 - VA - FERC | $0 | |
| 369 - NC - FERC | $0 | |
| **FERC Acc. 370 - Meters** | | |
| 370 - VA-SEC 56-235.2 | $72,625 | 72,625 |
| 370 - VA-NON-PVT MILITARY | -$467,357 | -467,357 |
| 370 - VA-NON-MICRON | $11,904 | 11,904 |
| 370 - Va - Non - NASA | $80,485 | 80,485 |
| 370 - Va - Non - MS | $1,176,702 | 1,176,702 |
| 370 - NC - Schedule NS | $90,290 | 90,290 |
| 370 - VA - FERC | 536,247 | 536,247 |
| 370 - NC - FERC | 71,327 | 71,327 |
| | 1,572,224 | |
| **FERC Acc. 373 - Streetlights (new for 2013)** | | |
| VA-NON-PVT MILITARY | $4,146,070 | 4,146,070 |
| Total Distribution Plant | | |

DISTRIBUTION PLANT

| | | | | | |
|---|---|---|---|---|---|
| LAND & LAND RIGHTS | | Distribution Plant Factors | | | |
| ASSIGNED FERC | 415,556 | | | | |
| ASSIGNED VA NON | 0 | | | | |
| SUBSTATION - DEMAND (VA | 37,936,216 | | | | |
| O.H. PRI - CUSTOMER (VA) | 1,206,404 | | 0.041536 | VA FERC 360 Allocators | V60POC |
| O.H. PRI - DEMAND (VA) | 3,489,105 | | 0.120127 | VA FERC 360 Allocators | V60POD |
| O.H. SEC - CUSTOMER (VA) | 1,071,221 | | 0.036881 | VA FERC 360 Allocators | V60SOC |
| O.H. SEC - DEMAND (VA) | 3,787,384 | | 0.130397 | VA FERC 360 Allocators | V60SOD |
| NON-DES UG - CUSTOMER ( | 1,820,164 | | 0.062667 | VA FERC 360 Allocators | V60UC |
| NON-DES UG - DEMAND (VA | 10,899,265 | | 0.375253 | VA FERC 360 Allocators | V60UD |
| TRANSFORMERS - CUSTOM | 525,953 | | 0.018108 | VA FERC 360 Allocators | V60TC |
| TRANSFORMERS - DEMAND | 6,245,586 | | 0.215031 | VA FERC 360 Allocators | V60TD |
| SUBSTATION - DEMAND (NC | 875,922 | | | | |
| O.H. PRI - CUSTOMER (NC) | 887,405 | | 0.469026 | NC FERC 360 Allocators | N60OPR |
| O.H. PRI - DEMAND (NC) | 316,813 | | 0.167447 | NC FERC 360 Allocators | N60OSR |
| NON-DES UG - CUSTOMER ( | 584,997 | | 0.309192 | NC FERC 360 Allocators | N60NDR |
| NON-DES UG - DEMAND (NC | 102,803 | | 0.054335 | NC FERC 360 Allocators | N60SCR |
| TOTAL ACCOUNT 360 | **70,164,794** | | | | |
| | | | 29,045,083 | VA FERC 360 | |
| STRUCTURES & IMPROVEMENTS | | | 1,892,017 | NC FERC 360 | |
| ASSIGNED FERC | 2,482,296 | | | | |
| ASSIGNED VA NON | 0 | | | | |
| SUBSTATION - DEMAND (VA | 74,713,037 | | | | |
| O.H. PRI - CUSTOMER (VA) | 96,244 | | 0.041536 | VA FERC 360 Allocators | V60POC |
| O.H. PRI - DEMAND (VA) | 278,351 | | 0.120127 | VA FERC 360 Allocators | V60POD |
| O.H. SEC - CUSTOMER (VA) | 85,459 | | 0.036881 | VA FERC 360 Allocators | V60SOC |
| O.H. SEC - DEMAND (VA) | 302,147 | | 0.130397 | VA FERC 360 Allocators | V60SOD |
| NON-DES UG - CUSTOMER ( | 145,208 | | 0.062667 | VA FERC 360 Allocators | V60UC |
| NON-DES UG - DEMAND (VA | 869,513 | | 0.375253 | VA FERC 360 Allocators | V60UD |
| TRANSFORMERS - CUSTOM | 41,959 | | 0.018108 | VA FERC 360 Allocators | V60TC |
| TRANSFORMERS - DEMAND | 498,256 | | 0.215031 | VA FERC 360 Allocators | V60TD |
| SUBSTATION - DEMAND (NC | 7,186,136 | | | | |
| O.H. PRI - CUSTOMER (NC) | 0 | | 0.469026 | NC FERC 360 Allocators | N60OPR |
| O.H. PRI - DEMAND (NC) | 0 | | 0.167447 | NC FERC 360 Allocators | N60OSR |
| NON-DES UG - CUSTOMER ( | 0 | | 0.309192 | NC FERC 360 Allocators | N60NDR |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| NON-DES UG - DEMAND (NC | 0 | 0.054335 | NC FERC 360 Allocators | N60SCR | | | |
| TOTAL ACCOUNT 361 | 86,698,606 | | | | | | |
| | | 2,317,137.00 | VA FERC 361 | | | | |
| STATION EQUIPMENT | | 0 | NC FERC 361 | | | | |
| ASSIGNED FERC | 36,025,359 | | | | | | |
| ASSIGNED VA NON | 2,081,151 | Virginia | | North Carolina | | | |
| SUBSTATION - DEMAND (VA) | 1,204,818,724 | 1,231,514,130 | | 84,214,325 | | | |
| SUBSTATION - DEMAND (NC | 72,803,221 | 26,695,406 | | 11,411,104 | | | |
| TOTAL ACCOUNT 362 | 1,315,728,456 | 1,204,818,724 | | 72,803,221 | | | |
| STORAGE BATTERY EQUIPMENT | | | | | | | |
| ALLOCATED | 0 | | | | | | |
| TOTAL ACCOUNT 363 | | | | | | | |
| POLES, TOWERS, & FIXTURES | | 792,795,545 | Virginia | | 77,404,210 | North Carolina | 364 |
| ASSIGNED FERC | 4,185,461 | | | | | | |
| ASSIGNED VA NON | 3,164,042 | 426,115,714 | Total Primary | | 76,470,432 | Total North Carolina excl. NC FERC | |
| PRIMARY - CUSTOMER (VA) | 170,907,711 | 366,679,832 | Total Secondary | | 51,366,389 | Total Primary | |
| PRIMARY - DEMAND (VA) | 248,792,277 | 252,595,429 | Total Primary Demand | | 25,104,043 | Total Secondary | |
| SECONDARY - CUSTOMER (' | 149,316,978 | 173,520,284 | Total Primary Customer | | **27,692,699** | **Primary - Customer** | |
| SECONDARY - DEMAND (VA) | 217,362,854 | **217,362,854** | **Secondary - Demand** | | **23,673,690** | **Primary - Demand** | |
| PRIMARY - CUSTOMER (NC) | 27,692,699 | **149,316,978** | **Secondary - Customer** | | **12,715,899** | **Secondary - Customer** | |
| PRIMARY - DEMAND (NC) | 23,673,690 | 3,803,152 | Primary Demand Assign | | **12,388,144** | **Secondary - Demand** | |
| SECONDARY - CUSTOMER (I | 12,715,899 | 2,612,573 | Primary Customer Assign | | 933,778 | Direct Assignment | |
| SECONDARY - DEMAND (NC | 12,388,144 | **248,792,277** | **Primary - Demand** | | | | |
| TOTAL ACCOUNT 364 | 870,199,755 | **170,907,711** | **Primary - Customer** | | | | |
| | | 792,795,545 | | | 77,404,210 | | |
| OVERHEAD CONDUCT & DEV | | 1,374,456,401 | Virginia | | 102,846,731 | North Carolina | 365 |
| ASSIGNED FERC | 19,276,583 | | | | | | |
| ASSIGNED VA NON | 8,318,451 | 669,970,526 | Total Primary | | 98,751,098 | Total NC excl. NC FERC | |
| PRIMARY - CUSTOMER (VA) | 103,252,429 | 704,485,875 | Total Secondary | | 66,588,526 | Total Primary | |
| PRIMARY - DEMAND (VA) | 543,218,696 | 562,964,843 | Total Primary Demand | | 32,162,572 | Total Secondary | |
| SECONDARY - CUSTOMER (' | 86,149,816 | 107,005,682 | Total Primary Customer | | **15,192,505** | **Primary - Customer** | |
| SECONDARY - DEMAND (VA) | 618,336,059 | **618,336,059** | **Secondary - Demand** | | **51,396,021** | **Primary - Demand** | |
| PRIMARY - CUSTOMER (NC) | 15,192,505 | **86,149,816** | **Secondary - Customer** | | **2,594,511** | **Secondary - Customer** | |
| PRIMARY - DEMAND (NC) | 51,396,021 | 19,746,147 | Primary Demand Assign | | **29,568,061** | **Secondary - Demand** | |

| | | | | | | |
|---|---|---|---|---|---|---|
| SECONDARY - CUSTOMER (I | 2,594,511 | 3,753,254 | Primary Customer Assign | 4,095,633 | Direct Assignment | |
| SECONDARY - DEMAND (NC | 29,568,061 | **543,218,696** | **Primary - Demand** | | | |
| TOTAL ACCOUNT 365 | **1,477,303,132** | **103,252,429** | **Primary - Customer** | | | |
| | | 1,374,456,401 | | 102,846,731 | | |
| UNDERGROUND CONDUIT | | 362,176,090 | Virginia | 6,779,399 | North Carolina | 366 |
| ASSIGNED FERC | 0 | | | | | |
| ASSIGNED VA NON | 997,382 | 310,348,289 | Total Demand | 6,779,399 | Total NC excl. NC FERC | |
| NON-DES UG - CUSTOMER ( | 51,685,074 | 51,827,801 | Total Customer | 5,397,822 | Total Primary | |
| NON-DES UG - DEMAND (VA) | 309,493,634 | 854,656 | Demand Assign | 1,381,577 | Total Secondary | |
| NON-DES UG - PRIMARY CUS | 1,729,829 | 142,726 | Customer Assign | **1,729,829** | **Primary - Customer** | |
| NON-DES UG - SECONDARY | 301,061 | **309,493,634** | **Demand** | **3,667,993** | **Primary - Demand** | |
| NON-DES UG - PRIMARY DEI | 3,667,993 | **51,685,074** | **Customer** | **301,061** | **Secondary - Customer** | |
| NON-DES UG - SECONDARY | 1,080,516 | | | **1,080,516** | **Secondary - Demand** | |
| TOTAL ACCOUNT 366 | **368,955,489** | | | 0 | Direct Assignment | |
| | | 362,176,090 | | 6,779,399 | | |
| UNDERGROUND CONDUCTORS | | 2,486,501,703 | Virginia | 105,093,290 | North Carolina | 367 |
| ASSIGNED FERC | 1,690,650 | | | | | |
| ASSIGNED VA NON | 17,814,123 | 2,130,680,549 | Total Demand | 104,236,537 | Total NC excl. NC FERC | |
| NON-DES UG - CUSTOMER ( | 353,152,601 | 355,821,154 | Total Customer | 82,819,529 | Total Primary | |
| NON-DES UG - DEMAND (VA) | 2,114,701,082 | 15,979,468 | Demand Assign | 21,417,008 | Total Secondary | |
| NON-DES UG - PRIMARY CUS | 26,541,009 | 2,668,552 | Customer Assign | **26,541,009** | **Primary - Customer** | |
| NON-DES UG - SECONDARY | 4,667,002 | **2,114,701,082** | **Demand** | **56,278,520** | **Primary - Demand** | |
| NON-DES UG - PRIMARY DEI | 56,278,520 | **353,152,601** | **Customer** | **4,667,002** | **Secondary - Customer** | |
| NON-DES UG - SECONDARY | 16,750,006 | | | **16,750,006** | **Secondary - Demand** | |
| TOTAL ACCOUNT 367 | **2,591,594,993** | | | 856,753 | Direct Assignment | |
| | | 2,486,501,703 | | 105,093,290 | | |
| LINE TRANSFORMERS | | 1,518,150,230 | Virginia | 70,544,442 | North Carolina | 368 |
| ASSIGNED FERC | 1,999,210 | | | | | |
| ASSIGNED VA NON | 2,615,556 | 1,400,233,983 | Total Demand | 70,357,145 | Total NC excl. NC FERC | |
| ALLOCATED - CUSTOMER (V | 117,572,361 | 117,916,247 | Total Customer | 61,039,370 | **Demand** | |
| ALLOCATED - DEMAND (VA) | 1,396,150,400 | 4,083,583 | Demand Assign | 9,317,775 | **Customer** | |
| ALLOCATED - CUSTOMER (N | 9,317,775 | 343,886 | Customer Assign | 187,297 | Direct Assignment | |
| ALLOCATED - DEMAND (NC) | 61,039,370 | **1,396,150,400** | **Demand** | | | |
| TOTAL ACCOUNT 368 | **1,588,694,672** | **117,572,361** | **Customer** | | | |
| | | 1,518,150,230 | | 70,544,442 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| SERVICES | | 1,422,562,735 | Virginia | 83,196,906 | North Carolina | 369 |
| ASSIGNED FERC | 0 | | | | | |
| ASSIGNED VA NON | 696,232 | 45,511,152 | Total Overhead - Dem | 83,196,906 | Total NC excl. NC FERC | |
| O.H. SEC - CUSTOMER (VA) | 61,660,142 | 62,061,818 | Total Overhead - Cust | 15,099,130 | Total Overhead | |
| O.H. SEC - DEMAND (VA) | 45,216,596 | 294,557 | Demand Assign | 68,097,776 | Total Underground | |
| NON-DES UG - CUSTOMER ( | 720,803,105 | 401,675 | Customer Assign | **3,295,729** | **Overhead - Customer** | |
| NON-DES UG - DEMAND (VA) | 594,186,660 | 45,216,596 | **Total Overhead - Dem** | **11,803,401** | **Overhead - Demand** | |
| O.H. SEC - CUSTOMER (NC) | 3,295,729 | 61,660,142 | **Total Overhead - Cust** | **35,902,695** | **Secondary - Customer** | |
| O.H. SEC - DEMAND (NC) | 11,803,401 | 594,186,660 | **Total Underground - Dem** | **32,195,081** | **Secondary - Demand** | |
| DES UG - CUSTOMER (NC) | 35,902,695 | 720,803,105 | **Total Underground - Cust** | 0 | Direct Assignment | |
| DES UG - DEMAND (NC) | 32,195,081 | | | | | |
| TOTAL ACCOUNT 369 | 1,505,759,641 | 1,422,562,735 | | 83,196,906 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| METERS | | | Virginia | | North Carolina | 370 |
| VA SEC 56-235.2 | 72,625 | OLD METHOD | | | | |
| VA NON PRIV MILITARY | (467,357) | This method replaced with the new method on 370 reallocation tab | | | | |
| VA NON-MICRON | 11,904 | | | | | |
| VA NON-NASA | 80,485 | | | | | |
| VA NON-MS | 1,176,702 | | | | | |
| NC - SCHEDULE NS | 90,290 | | | | | |
| VA FERC | 536,247 | 510,358,444 | Total Virginia | 13,726,957 | Total North Carolina | |
| NC FERC | 71,327 | | | | | |
| AMI METERS - RIDER A5 POI | 0 | 0 | | | | |
| ALLOCATED - CUSTOMER (V | 508,947,838 | 1,410,606 | Direct Assignment | 161,617 | Direct Assignment | |
| ALLOCATED - CUSTOMER (N | 13,565,340 | **508,947,838** | **Customer** | **13,565,340** | **Customer** | |
| TOTAL ACCOUNT 370 | 524,085,401 | | | | | |

| | |
|---|---|
| INSTALLATION ON CUSTOMER PREMISE | |
| ASSIGNED (VA) | 2,854,243 |
| FERC Acct 371.)Va - C1 VA | 18,568,786 |
| FERC Acct 371.)Va - C2 VA | 0 |
| ASSIGNED (NC) | 713,072 |
| FERC Acct 371.0 NC - C1 NC | 886,158 |
| FERC Acct 371.0 NC - C2 NC | 0 |
| TOTAL ACCOUNT 371 | 23,022,259 |

| | | | | |
|---|---|---|---|---|
| STREET LIGHTS & SIGNAL SYSTEMS | | | | |
| **ASSIGNED (VA) NEW 2013** | 4,146,070 | 333,964,652 | | 373 |
| OUTDOOR LIGHTING - CUST | 83,058,129 | 83,058,129 | **Outdoor Lighting** | |
| PUBLIC AUTHORITIES - CUS | 250,906,523 | **250,906,523** | **Public Authorities** | |
| ASSIGNED (NC) | 19,461,788 | | | |
| TOTAL ACCOUNT 373 | 357,572,510 | | | |

| | | | |
|---|---|---|---|
| FERC ACCT 360 ASSIGNED FERC | 415,556 | 360 | |
| FERC ACCT 360 ASSIGNED VA NON | 0 | 360 | |
| FERC ACCT 360 SUBSTATION - DEMAND (VA) | 37,936,216 | 360 | |
| FERC ACCT 360 O.H. PRI - CUSTOMER (VA) | 1,206,404 | 360 | |
| FERC ACCT 360 O.H. PRI - DEMAND (VA) | 3,489,105 | 360 | |
| FERC ACCT 360 O.H. SEC - CUSTOMER (VA) | 1,071,221 | 360 | |
| FERC ACCT 360 O.H. SEC - DEMAND (VA) | 3,787,384 | 360 | |
| FERC ACCT 360 NON-DES UG - CUSTOMER (VA) | 1,820,164 | 360 | |
| FERC ACCT 360 NON-DES UG - DEMAND (VA) | 10,899,265 | 360 | |
| FERC ACCT 360 TRANSFORMERS - CUSTOMER (VA) | 525,953 | 360 | |
| FERC ACCT 360 TRANSFORMERS - DEMAND (VA) | 6,245,586 | 360 | |
| FERC ACCT 360 SUBSTATION - DEMAND (NC) | 875,922 | 360 | |
| FERC ACCT 360 O.H. PRI - CUSTOMER (NC) | 887,405 | 360 | |
| FERC ACCT 360 O.H. PRI - DEMAND (NC) | 316,813 | 360 | |
| FERC ACCT 360 NON-DES UG - CUSTOMER (NC) | 584,997 | 360 | |
| FERC ACCT 360 NON-DES UG - DEMAND (NC) | 102,803 | 360 | 70,164,794 |
| FERC ACCT 361 ASSIGNED FERC | 2,482,296 | 361 | |
| FERC ACCT 361 ASSIGNED VA NON | 0 | 361 | |
| FERC ACCT 361 SUBSTATION - DEMAND (VA) | 74,713,037 | 361 | |
| FERC ACCT 361 O.H. PRI - CUSTOMER (VA) | 96,244 | 361 | |
| FERC ACCT 361 O.H. PRI - DEMAND (VA) | 278,351 | 361 | |
| FERC ACCT 361 O.H. SEC - CUSTOMER (VA) | 85,459 | 361 | |
| FERC ACCT 361 O.H. SEC - DEMAND (VA) | 302,147 | 361 | |
| FERC ACCT 361 NON-DES UG - CUSTOMER (VA) | 145,208 | 361 | |
| FERC ACCT 361 NON-DES UG - DEMAND (VA) | 869,513 | 361 | |
| FERC ACCT 361 TRANSFORMERS - CUSTOMER (VA) | 41,959 | 361 | |
| FERC ACCT 361 TRANSFORMERS - DEMAND (VA) | 498,256 | 361 | |
| FERC ACCT 361 SUBSTATION - DEMAND (NC) | 7,186,136 | 361 | |
| FERC ACCT 361 O.H. PRI - CUSTOMER (NC) | 0 | 361 | |
| FERC ACCT 361 O.H. PRI - DEMAND (NC) | 0 | 361 | |
| FERC ACCT 361 NON-DES UG - CUSTOMER (NC) | 0 | 361 | |
| FERC ACCT 361 NON-DES UG - DEMAND (NC) | 0 | 361 | 86,698,606 |
| FERC ACCT 362 ASSIGNED FERC | 36,025,359 | 362 | |
| FERC ACCT 362 ASSIGNED VA NON | 2,081,151 | 362 | |
| FERC ACCT 362 SUBSTATION - DEMAND (VA) | 1,204,818,724 | 362 | |
| FERC ACCT 362 SUBSTATION - DEMAND (NC) | 72,803,221 | 362 | 1,315,728,456 |
| FERC ACCT 363 ALLOCATED | 0 | 363 | |
| FERC ACCT 364 ASSIGNED FERC | 4,185,461 | 364 | |
| FERC ACCT 364 ASSIGNED VA NON | 3,164,042 | 364 | |
| FERC ACCT 364 PRIMARY - CUSTOMER (VA) | 170,907,711 | 364 | |
| FERC ACCT 364 PRIMARY - DEMAND (VA) | 248,792,277 | 364 | |
| FERC ACCT 364 SECONDARY - CUSTOMER (VA) | 149,316,978 | 364 | |
| FERC ACCT 364 SECONDARY - DEMAND (VA) | 217,362,854 | 364 | |
| FERC ACCT 364 PRIMARY - CUSTOMER (NC) | 27,692,699 | 364 | |
| FERC ACCT 364 PRIMARY - DEMAND (NC) | 23,673,690 | 364 | |
| FERC ACCT 364 SECONDARY - CUSTOMER (NC) | 12,715,899 | 364 | |
| FERC ACCT 364 SECONDARY - DEMAND (NC) | 12,388,144 | 364 | 870,199,755 |
| FERC ACCT 365 ASSIGNED FERC | 19,276,583 | 365 | |
| FERC ACCT 365 ASSIGNED VA NON | 8,318,451 | 365 | |
| FERC ACCT 365 PRIMARY - CUSTOMER (VA) | 103,252,429 | 365 | |
| FERC ACCT 365 PRIMARY - DEMAND (VA) | 543,218,696 | 365 | |
| FERC ACCT 365 SECONDARY - CUSTOMER (VA) | 86,149,816 | 365 | |
| FERC ACCT 365 SECONDARY - DEMAND (VA) | 618,336,059 | 365 | |
| FERC ACCT 365 PRIMARY - CUSTOMER (NC) | 15,192,505 | 365 | |
| FERC ACCT 365 PRIMARY - DEMAND (NC) | 51,396,021 | 365 | |
| FERC ACCT 365 SECONDARY - CUSTOMER (NC) | 2,594,511 | 365 | |
| FERC ACCT 365 SECONDARY - DEMAND (NC) | 29,568,061 | 365 | 1,477,303,132 |
| FERC ACCT 366 ASSIGNED FERC | 0 | 366 | |
| FERC ACCT 366 ASSIGNED VA NON | 997,382 | 366 | |
| FERC ACCT 366 NON-DES UG - CUSTOMER (VA) | 51,685,074 | 366 | |
| FERC ACCT 366 NON-DES UG - DEMAND (VA) | 309,493,634 | 366 | |

| | | | |
|---|---|---|---|
| FERC ACCT 366 NON-DES UG - PRIMARY CUST (NC) | 1,729,829 | 366 | |
| FERC ACCT 366 NON-DES UG - SECONDARY CUST (NC) | 301,061 | 366 | |
| FERC ACCT 366 NON-DES UG - PRIMARY DEMAND (NC) | 3,667,993 | 366 | |
| FERC ACCT 366 NON-DES UG - SECONDARY DEMAND (NC) | 1,080,516 | 366 | 368,955,489 |
| FERC ACCT 367 ASSIGNED FERC | 1,690,650 | 367 | |
| FERC ACCT 367 ASSIGNED VA NON | 17,814,123 | 367 | |
| FERC ACCT 367 NON-DES UG - CUSTOMER (VA) | 353,152,601 | 367 | |
| FERC ACCT 367 NON-DES UG - DEMAND (VA) | 2,114,701,082 | 367 | |
| FERC ACCT 367 NON-DES UG - PRIMARY CUST (NC) | 26,541,009 | 367 | |
| FERC ACCT 367 NON-DES UG - SECONDARY CUST (NC) | 4,667,002 | 367 | |
| FERC ACCT 367 NON-DES UG - PRIMARY DEMAND (NC) | 56,278,520 | 367 | |
| FERC ACCT 367 NON-DES UG - SECONDARY DEMAND (NC) | 16,750,006 | 367 | 2,591,594,993 |
| FERC ACCT 368 ASSIGNED FERC | 1,999,210 | 368 | |
| FERC ACCT 368 ASSIGNED VA NON | 2,615,556 | 368 | |
| FERC ACCT 368 ALLOCATED - CUSTOMER (VA) | 117,572,361 | 368 | |
| FERC ACCT 368 ALLOCATED - DEMAND (VA) | 1,396,150,400 | 368 | |
| FERC ACCT 368 ALLOCATED - CUSTOMER (NC) | 9,317,775 | 368 | |
| FERC ACCT 368 ALLOCATED - DEMAND (NC) | 61,039,370 | 368 | 1,588,694,672 |
| FERC ACCT 369 ASSIGNED FERC | 0 | 369 | |
| FERC ACCT 369 ASSIGNED VA NON | 696,232 | 369 | |
| FERC ACCT 369 O.H. SEC - CUSTOMER (VA) | 61,660,142 | 369 | |
| FERC ACCT 369 O.H. SEC - DEMAND (VA) | 45,216,596 | 369 | |
| FERC ACCT 369 NON-DES UG - CUSTOMER (VA) | 720,803,105 | 369 | |
| FERC ACCT 369 NON-DES UG - DEMAND (VA) | 594,186,660 | 369 | |
| FERC ACCT 369 O.H. SEC - CUSTOMER (NC) | 3,295,729 | 369 | |
| FERC ACCT 369 O.H. SEC - DEMAND (NC) | 11,803,401 | 369 | |
| FERC ACCT 369 DES UG - CUSTOMER (NC) | 35,902,695 | 369 | |
| FERC ACCT 369 DES UG - DEMAND (NC) | 32,195,081 | 369 | 1,505,759,641 |
| FERC ACCT 370 ASSIGNED VA SEC 56-235.2 | 72,625 | 370 | |
| FERC ACCT 370 ASSIGNED PRIV MILITARY | (467,357) | 370 | |
| FERC ACCT 370 ASSIGNED VA NON-MICRON | 11,904 | 370 | |
| FERC ACCT 370 ASSIGNED VA NON-NASA | 80,485 | 370 | |
| FERC ACCT 370 ASSIGNED VA NON-MS | 1,176,702 | 370 | |
| FERC ACCT 370 ASSIGNED NC SCHEDULE NS | 90,290 | 370 | |
| FERC ACCT 370 ASSIGNED FERC VA | 536,247 | 370 | |
| FERC ACCT 370 ASSIGNED FERC NC | 71,327 | 370 | |
| FERC ACCT 370 AMI METERS - RIDER A5 PORTION | | 370 | |
| FERC ACCT 370 ALLOCATED - CUSTOMER (VA) | 508,947,838 | 370 | 524,085,401 |
| FERC ACCT 370 ALLOCATED - CUSTOMER (NC) | 13,565,340 | 370 | |
| FERC ACCT 371 ASSIGNED (VA) | 2,854,243 | 371 | |
| FERC Acct 371.)Va - C1 VA | 18,568,786 | 371 | |
| FERC Acct 371.)Va - C2 VA | 0 | 371 | |
| FERC Acct 371.0 NC | 713,072 | 371 | |
| FERC Acct 371.0 NC - C1 NC | 886,158 | 371 | |
| FERC Acct 371.0 NC - C2 NC | 0 | 371 | 23,022,259 |
| FERC ACCT 373 OUTDOOR LIGHTING - CUSTOMER | 83,058,129 | 373 | |
| FERC ACCT 373 PUBLIC AUTHORITIES - CUSTOMER | 250,906,523 | 373 | |
| FERC ACCT 373 ASSIGNED | 19,461,788 | 373 | |
| **FERC ACCT 373 PRI MILITARY NEW 2013** | 4,146,070 | | 357,572,510 |
| | 10,779,779,708 | | 10,779,779,708 |
| | 357,572,510 | | |
| Total 370 dist model | 524,085,401 | | |
| Total 370 FA | 524,085,401 | | |
| total assigned dist | 1,572,224 | | |

# Distribution Model for the State of North Carolina

### *Average Daily Load Duration Curve Data:*

| Class | Cust | Demand |
|---|---|---|
| State of NC* | 64.92% | 35.08% |

** Distribution customers only and FERC customers removed*

| NC State Distribution Load Duration Summary | | | |
|---|---|---|---|
| Mininmum vs. Maximum load per day Summary | | | |
| Year | Peak Season | Zone Peak | Max/Min average ratio |
| 2015 | Winter | 21,651 MW | 64.74% |
| 2016 | Summer | 19,538 MW | 65.79% |
| 2017 | Winter | 19,661 MW | 64.24% |
| | | 3-year Average | 64.92% |

### *Primary/Secondary GIS Study:*

| Equipment | Primary | Secondary |
|---|---|---|
| Poles | 75.86% | 24.14% |
| Overhead | 84.39% | 15.61% |
| Underground | 39.86% | 60.14% |

### *Peak Demands/Customer Allocation Factors*

| | NC Total | Res | SGS | LGS | 6 VP | Street | Traffic |
|---|---|---|---|---|---|---|---|
| **Customer-Pri** | | | | | | | |
| # of Cust | 84 | - | 70 | 11 | 3 | - | - |
| Allocation | 100.00% | 0.00% | 83.33% | 13.10% | 3.57% | 0.00% | 0.00% |
| **Customer-Sec** | | | | | | | |
| # of Cust | 134,274 | 102,620 | 17,627 | 46 | - | 13,935 | 46 |
| Allocation | 100.00% | 76.43% | 13.13% | 0.03% | 0.00% | 10.38% | 0.03% |
| **Customer -Total** | | | | | | | |
| # of Cust | 134,358 | 102,620 | 17,697 | 57 | 3 | 13,935 | 46 |
| Allocation | 100.00% | 76.38% | 13.17% | 0.04% | 0.00% | 10.37% | 0.03% |
| **Demand-Pri** | | | | | | | |
| Peak Demand | 884,309 | 552,125 | 166,912 | 101,621 | 56,467 | 7,119 | 65 |
| Allocation | 100% | 62.44% | 18.87% | 11.49% | 6.39% | 0.81% | 0.01% |
| **Demand-Sec** | | | | | | | |
| Peak Demand | 753,020 | 527,364 | 154,147 | 64,647 | - | 6,800 | 62 |
| Allocation | 100.00% | 70.03% | 20.47% | 8.59% | 0.00% | 0.90% | 0.01% |

## 360 Land and land rights.

This account shall include the cost of land and land rights used in connection with distribution operations. (See electric plant instruction 7.)

NOTE: Do not include in this account the cost of permits to erect poles, towers, etc., or to trim trees. (See account 364, Poles, Towers and Fixtures, and account 365, Overhead Conductors and Devices.)

## 361 Structures and improvements.

This account shall include the cost in place of structures and improvements used in connection with distribution operations. (See electric plant instruction 8.)

## 362 Station equipment.

This account shall include the cost installed of station equipment, including transformer banks, etc., which are used for the purpose of changing the characteristics of electricity in connection with its distribution.

ITEMS

1. Bus compartments, concrete, brick and sectional steel, including items permanently attached thereto.

2. Conduit, including concrete and iron duct runs not part of building.

3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards, and connections.

4. Conversion equipment, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment, and associated connections.

5. Fences.

6. Fixed and synchronous condensers, including transformers, switching equipment, blowers, motors, and connections.

7. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.

8. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.

9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.

10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arresters, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arresters, and accessory equipment.

11. Switchboards, including meters, relays, control wiring, etc.

12. Switching equipment, indoor and outdoor, including oil circuit breakers and operating mechanisms, truck switches, disconnect switches.

NOTE: The cost of rectifiers, series transformers, and other special station equipment devoted exclusively to street lighting service shall not be included in this account, but in account 373, Street Lighting and Signal Systems.

## 363 Energy Storage Equipment—Distribution

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchased to energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 582.1, Operation of Energy Storage Equipment, and Account, 592.1, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

## 364 Poles, towers and fixtures.

This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

ITEMS

1. Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Crossarms and braces.
4. Excavation and backfill, including disposal of excess excavated material.
5. Extension arms.
6. Foundations.

7. Guards.

8. Insulator pins and suspension bolts.

9. Paving.

10. Permits for construction.

11. Pole steps and ladders.

12. Poles, wood, steel, concrete, or other material.

13. Racks complete with insulators.

14. Railings.

15. Reinforcing and stubbing.

16. Settings.

17. Shaving, painting, gaining, roofing, stenciling, and tagging.

18. Towers.

19. Transformer racks and platforms.

## 365 Overhead conductors and devices.

This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

ITEMS

1. Circuit breakers.

2. Conductors, including insulated and bare wires and cables.

3. Ground wires, clamps, etc.

4. Insulators, including pin, suspension, and other types, and tie wire or clamps.

5. Lightning arresters.

6. Railroad and highway crossing guards.

7. Splices.

8. Switches.

9. Tree trimming, initial cost including the cost of permits therefor.

10. Other line devices.

NOTE: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 373, Street Lighting and Signal Systems.

## 366 Underground conduit.

This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

ITEMS

1. Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.

2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.

3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed.

4. Lighting systems.

5. Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.

6. Municipal inspection.

7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.

9. Protection of street openings.

10. Removal and relocation of subsurface obstructions.

11. Sewer connections, including drains, traps, tide valves, check valves, etc.

12. Sumps, including pumps.

13. Ventilating equipment.

NOTE: The cost of underground conduit used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

## 367 Underground conductors and devices.

This account shall include the cost installed of underground conductors and devices used for distribution purposes.

ITEMS

1. Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc.

2. Armored conductors, submarine, including insulators, insulating materials, splices in terminal chamber, potheads, etc.

3. Cables in standpipe, including pothead and connection from terminal chamber or manhole to insulators on pole.

4. Circuit breakers.

5. Fireproofing, in connection with any items listed herein.

6. Hollow-core oil-filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc.

7. Lead and fabric covered conductors, including insulators, compound-filled, oil-filled or vacuum splices, potheads, etc.

8. Lightning arresters.

9. Municipal inspection.

10. Permits.

11. Protection of street openings.

12. Racking of cables.

13. Switches.

14. Other line devices.

NOTE: The cost of underground conductors and devices used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

## 368 Line transformers.

A. This account shall include the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve.

B. When a transformer is permanently retired from service, the original installed cost thereof shall be credited to this account.

C. The records covering line transformers shall be so kept that the utility can furnish the number of transformers of various capacities in service and those in reserve, and the location and the use of each transformer.

ITEMS

1. Installation, labor of (first installation only).

2. Transformer cut-out boxes.

3. Transformer lightning arresters.

4. Transformers, line and network.

5. Capacitors.

6. Network protectors.

NOTE: The cost of removing and resetting line transformers shall not be charged to this account but to account 583, Overhead Line Expenses, or account 584, Underground Line Expenses (for Nonmajor utilities, account 561, Line and Station Labor, or account 562, Line and Station Supplies and Expenses), as appropriate. The cost of line transformers used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

## 369 Services.

This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the distribution box or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring. Conduit used for underground service conductors shall be included herein.

ITEMS

1. Brackets.

2. Cables and wires.

3. Conduit.

4. Insulators.

5. Municipal inspection.

6. Overhead to underground, including conduit or standpipe and conductor from last splice on pole to connection with customer's wiring.

7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.

9. Protection of street openings.

10. Service switch.

11. Suspension wire.

## 370 Meters.

A. This account shall include the cost installed of meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users, whether actually in service or held in reserve.

B. When a meter is permanently retired from service, the installed cost included herein shall be credited to this account.

C. The records covering meters shall be so kept that the utility can furnish information as to the number of meters of various capacities in service and in reserve as well as the location of each meter owned.

ITEMS

1. Alternating current, watt-hour meters.
2. Current limiting devices.
3. Demand indicators.
4. Demand meters.
5. Direct current watt-hour meters.
6. Graphic demand meters.
7. Installation, labor of (first installation only).
8. Instrument transformers.
9. Maximum demand meters.
10. Meter badges and their attachments.
11. Meter boards and boxes.
12. Meter fittings, connections, and shelves (first set).
13. Meter switches and cut-outs.
14. Prepayment meters.
15. Protective devices.
16. Testing new meters.

NOTE A: This account shall not include meters for recording output of a generating station, substation meters, etc. It includes only those meters used to record energy delivered to customers.

NOTE B: The cost of removing and resetting meters shall be charged to account 586, Meter Expenses (for Nonmajor utilities, account 556, Meter Expenses).

## 371 Installations on customers' premises.

This account shall include the cost installed of equipment on the customer's side of a meter when the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property. This account shall not include leased equipment, for which see account 372, Leased Property on Customers' Premises.

ITEMS

1. Cable vaults.
2. Commercial lamp equipment.

3. Foundations and settings specially provided for equipment included herein.

4. Frequency changer sets.

5. Motor generator sets.

6. Motors.

7. Switchboard panels, high or low tension.

8. Wire and cable connections to incoming cables.

NOTE: Do not include in this account any costs incurred in connection with merchandising, jobbing, or contract work activities.

## 372 Leased property on customers' premises.

This account shall include the cost of electric motors, transformers, and other equipment on customers' premises (including municipal corporations), leased or loaned to customers, but not including property held for sale.

NOTE A: The cost of setting and connecting such appliances or equipment on the premises of customers and the cost of resetting or removal shall not be charged to this account but to operating expenses, account 587, Customer Installations Expenses (for Nonmajor utilities, account 567, Customer Installations Expenses).

NOTE B: Do not include in this account any costs incurred in connection with merchandising, jobbing, or contract work activities.

## 373 Street lighting and signal systems.

This account shall include the cost installed of equipment used wholly for public street and highway lighting or traffic, fire alarm, police, and other signal systems.

ITEMS

1. Armored conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc.

2. Automatic control equipment.

3. Conductors, overhead or underground, including lead or fabric covered, parkway cables, etc., including splices, insulators, etc.

4. Lamps, are, incandescent, or other types, including glassware, suspension fixtures, brackets, etc.

5. Municipal inspection.

6. Ornamental lamp posts.

7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.

8. Permits.

9. Posts and standards.

10. Protection of street openings.

11. Relays or time clocks.

12. Series contactors.

13. Switches.

14. Transformers, pole or underground.

## 580 Operation supervision and engineering.

This account shall include the cost of labor and expenses incurred in the general supervision and direction of the operation of the distribution system. Direct supervision of specific activities, such as station operation, line operation, meter department operation, etc., shall be charged to the appropriate account. (For Major utilities, see operating expense instruction 1.)

## 581 Load dispatching (Major only).

This account (the keeping of which is optional with the utility) shall include the cost of labor, materials used and expenses incurred in load dispatching operations pertaining to the distribution of electricity.

ITEMS

Labor:

1. Directing switching.

2. Arranging and controlling clearances for construction, maintenance, test and emergency purposes.

3. Controlling system voltages.

4. Preparing operating reports.

5. Obtaining reports on the weather and special events.

Expenses:

6. Communication service provided for system control purposes.

7. System record and report forms.

8. Meals, traveling and incidental expenses.

## 581.1 Line and station supplies and expenses (Nonmajor only).

## 582 Station expenses (Major only).

## 583 Overhead line expenses (Major only).

## 584 Underground line expenses (Major only).

Accounts 581.1 through 584 shall include, respectively, the cost of labor, materials used and expenses incurred in the operation of overhead and underground distribution lines and stations.

ITEMS

Line Labor:

1. Supervising line operation.

2. Changing line transformer taps.

3. Inspecting and testing lightning arresters, line circuit breakers, switches and grounds.

4. Inspecting and testing line transformers for the purpose of determining load, temperature or operating performance.

5. Patrolling lines.

6. Load tests and voltages surveys of feeders, circuits and line transformers.

7. Removing line transformers and voltage regulators with or without replacements.

8. Installing line transformers or voltage regulators with or without change in capacity provided that the first installation of these items is included in account 368, Line transformers.

9. Voltage surveys, either routine or upon request of customers, including voltage tests at customers' main switch.

10. Transferring loads, switching and reconnecting circuits and equipment for operation purposes.

11. Electrolysis surveys.

12. Inspecting and adjusting line testing equipment.

Line Supplies and Expenses:

13. Tool expenses.

14. Transportation expenses.

15. Meals, traveling and incidental expense.

16. Operating supplies, such as instrument charts, rubber goods, etc.

Station Labor:

1. Supervising station operation.

2. Adjusting station equipment where such adjustment primarily affects performance, such as regulating the flow of cooling water, adjusting current in fields of a machine, changing voltage of regulators or changing station transformer taps.

3. Keeping station log and records and preparing reports on station operation.

4. Inspecting, testing and calibrating station equipment for the purpose of checking its performance.

5. Operating switching and other station equipment.

6. Standing watch, guarding and patrolling station and station yard.

7. Sweeping, mopping and tidying station.

8. Care of grounds, including snow removal, cutting grass, etc.

Station Supplies and Expenses:

9. Building service expenses.

10. Operating supplies, such as lubricants, commutator brushes, water and rubber goods.

11. Station meter and instrument supplies, such as ink and charts.

12. Station record and report forms.

13. Tool expenses.

14. Transportation expenses.

15. Meals, traveling and incidental expenses.

NOTE (MAJOR ONLY): If the utility owns storage battery equipment used for supplying electricity to customers in periods of emergency, the cost of operating labor and of supplies, such as acid, gloves, hydrometers, thermometers, soda, automatic cell fillers, acid proof shoes, etc., shall be included in this account. If significant in amount, a separate subdivision shall be maintained for such expenses.

## 584.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 363, Energy Storage Equipment—Distribution, which are not specifically provided for or are readily assignable to other distribution operation expense accounts.

## 585 Street lighting and signal system expenses.

A. For Nonmajor utilities, this account shall include the cost of labor, materials used and expenses incurred in the operation of street lighting and signal system plant.

B. For Major utilities, this account shall include the cost of labor, materials used and expenses incurred in: (a) The operation of street lighting and signal system plant which is owned or leased by the utility; and (b) the operation and maintenance of such plant owned by customers where such work is done regularly as a part of the street lighting and signal system service.

ITEMS

Labor:

1. Supervising street lighting and signal systems operation.

2. Replacing lamps and incidental cleaning of glassware and fixtures in connection therewith.

3. Routine patrolling for lamp outages, extraneous nuisances or encroachments, etc.

4. Testing lines and equipment including voltage and current measurement.

5. Winding and inspection of time switch and other controls.

Materials and Expenses:

6. Street lamp renewals.

7. Transportation and tool expense.

8. Meals, traveling, and incidental expenses.

## 586 Meter expenses.

This account shall include the cost of labor, materials used and expenses incurred in the operation of customer meters and associated equipment.

ITEMS

Labor:

1. Supervising meter operation.

2. Clerical work on meter history and associated equipment record cards, test cards, and reports.

3. Disconnecting and reconnecting, removing and reinstalling, sealing and unsealing meters and other metering equipment in connection with initiating or terminating services including the cost of obtaining meter readings, if incidental to such operation.

4. Consolidating meter installations due to elimination of separate meters for different rates of service.

5. Changing or relocating meters, instrument transformers, time switches, and other metering equipment.

6. Resetting time controls, checking operation of demand meters and other metering equipment, when done as an independent operation.

7. Inspecting and adjusting meter testing equipment.

8. Inspecting and testing meters, instrument transformers, time switches, and other metering equipment on premises or in shops excluding inspecting and testing incidental to maintenance

Materials and Expenses:

9. Meter seals and miscellaneous meter supplies.

10. Transportation expenses.

11. Meals, traveling, and incidental expenses.

12. Tool expenses.

NOTE: The cost of the first setting and testing of a meter is chargeable to utility plant account 370, Meters.

## 587 Customer installations expenses.

This account shall include the cost of labor, materials used and expenses incurred in work on customer installations in inspecting premises and in rendering services to customers of the nature of those indicated by the list of items hereunder.

ITEMS

Labor:

1. Supervising customer installations work.

2. Inspecting premises, including check of wiring for code compliance.

3. Investigating, locating, and clearing grounds on customers' wiring.

4. Investigating service complaints, including load tests of motors and lighting and power circuits on customers' premises; field investigations of complaints on bills or of voltage.

5. Installing, removing, renewing, and changing lamps and fuses.

6. Radio, television and similar interference work including erection of new aerials on customers' premises and patrolling of lines, testing of lightning arresters, inspection of pole hardware, etc., and examination on or off premises of customers' appliances, wiring, or equipment to locate cause of interference.

7. Installing, connecting, reinstalling, or removing leased property on customers' premises.

8. Testing, adjusting, and repairing customers' fixtures and appliances in shop or on premises.

9. Cost of changing customers' equipment due to changes in service characteristics.

10. Investigation of current diversion including setting and removal of check meters and securing special readings thereon; special calls by employees in connection with discovery and settlement of current diversion; changes in customer wiring and any other labor cost identifiable as caused by current diversion.

Materials and Expenses:

11. Lamp and fuse renewals.

12. Materials used in servicing customers' fixtures, appliances and equipment.

13. Power, light, heat, telephone, and other expenses of appliance repair department.

14. Tool expense.

15. Transportation expense, including pickup and delivery charges.

16. Meals, traveling and incidental expenses.

17. Rewards paid for discovery of current diversion.

NOTE A: Amounts billed customers for any work, the cost of which is charged to this account, shall be credited to this account. Any excess over costs resulting therefrom shall be transferred to account 451, Miscellaneous Service Revenues.

NOTE B: Do not include in this account expenses incurred in connection with merchandising, jobbing and contract work.

## 588 Miscellaneous distribution expenses.

This account shall include the cost of labor, materials used and expenses incurred in distribution system operation not provided for elsewhere.

ITEMS

Labor:

1. General records of physical characteristics of lines and substations, such as capacities, etc.

2. Ground resistance records.

3. Joint pole maps and records.

4. Distribution system voltage and load records.

5. Preparing maps and prints.

6. Service interruption and trouble records.

7. General clerical and stenographic work except that chargeable to account 586, Meter expenses.

Expenses:

8. Operating records covering poles, transformers, manholes, cables, and other distribution facilities. Exclude meter records chargeable to account 586. Meter Expenses and station records chargeable to account 582, Station Expenses (For Nonmajor utilities, account 581.1, Line and Station Expenses), and stores records (For Nonmajor utilities, station records) chargeable to account 163, Stores Expense Undistributed (For Nonmajor utilities, account 581.1, Line and Station Expenses).

9. Janitor work at distribution office buildings including snow removal, cutting grass, etc.

Materials and Expenses:

10. Communication service.

11. Building service expenses.

12. Miscellaneous office supplies and expenses, printing, and stationery, maps and records and first-aid supplies.

13. Research, development, and demonstration expenses (Major only).

## 589 Rents.

This account shall include rents of property of others used, occupied, or operated in connection with the distribution system, including payments to the United States and others for the use and occupancy of public lands and reservations for distribution line rights of way. (See operating expense instruction 3.)

## 590 Maintenance supervision and engineering (Major only).

This account shall include the cost of labor and expenses incurred in the general supervision and direction of maintenance of the distribution system. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account. (See operating expense instruction 1.)

## 591 Maintenance of structures (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements. (See operating expense instruction 2.)

## 592 Maintenance of station equipment (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 362, Station Equipment, and account 363, Storage Battery Equipment. (See operating expense instruction 2.)

## 592.1 Maintenance of Structures and Equipment (Nonmajor Only)

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements, and account 362, Station Equipment. (See operating expense instruction 2.)

## 593 Maintenance of overhead lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on poles.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacements.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulty lines clear, or similar activities at times of emergency.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on overhead services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

## 594 Maintenance of underground lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is includible in account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls, and floors, rings and covers.

2. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manholes including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable systems and replacement of oil or gas.

3. Work of the following character on underground services:

a. Cleaning ducts.

b. Repairing any underground service plant.

## 594.1 Maintenance of lines (Nonmajor only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on pole.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvage for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacement.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulting lines clear, or similar activities at times of emergencies.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls and floors, rings and covers.

4. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manhole including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable system and replacement of oil or gas.

5. Work of the following character on services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

e. Cleaning ducts.

## 595 Maintenance of line transformers.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of distribution line transformers, the book cost of which is includible in account 368, Line Transformers. (See operating expense instruction 2.)

## 596 Maintenance of street lighting and signal systems.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 373, Street Lighting and Signal Systems. (See operating expense instruction 2.)

## 597 Maintenance of meters.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of meters and meter testing equipment, the book cost of which is includible in account 370, Meters, and account 395, Laboratory Equipment, respectively. (See operating expense instruction 2.)

## 598 Maintenance of miscellaneous distribution plant.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in accounts 371, Installations on Customers' Premises, and 372, Leased Property on Customers' Premises, and any other plant the maintenance of which is assignable to the distribution function and is not provided for elsewhere. (See operating expense instruction 2.)

ITEMS

a. Work of similar nature to that listed in other distribution maintenance accounts.

b. Maintenance of office furniture and equipment used by distribution system department.

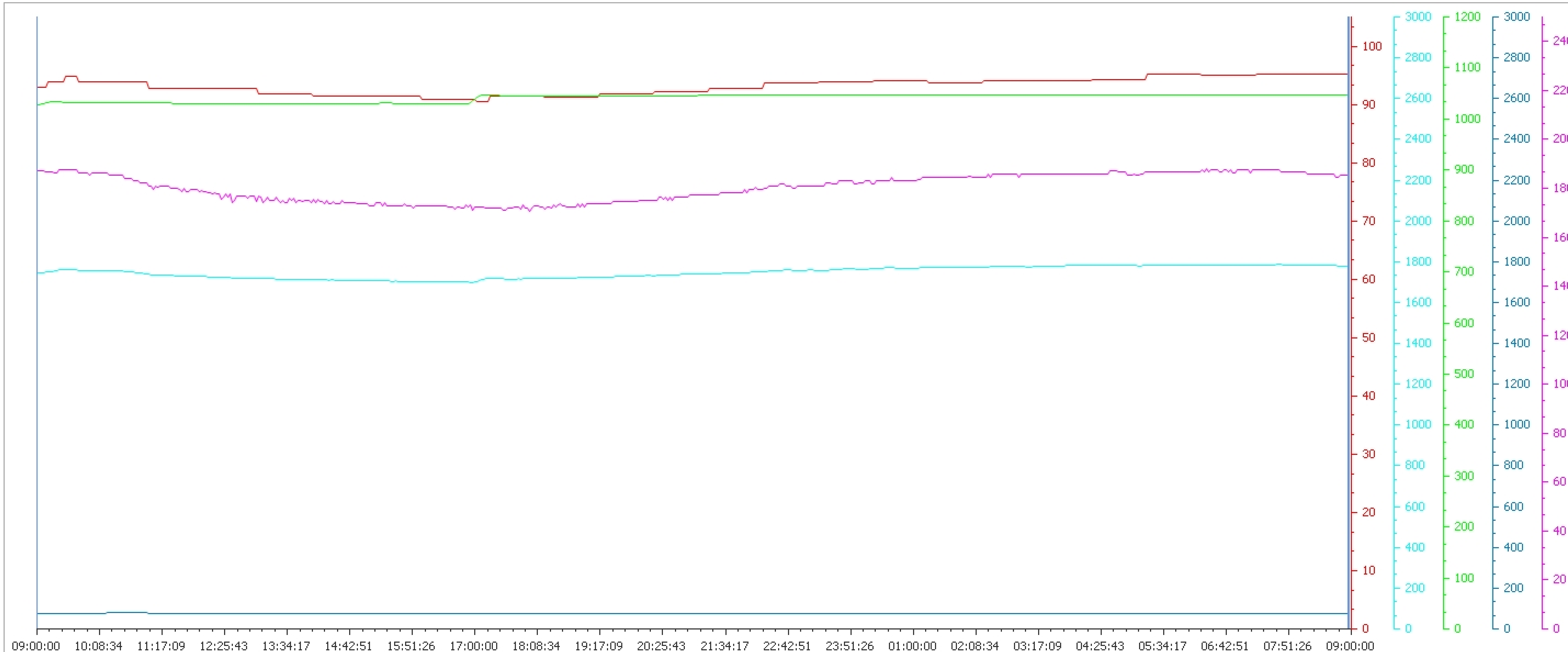
**Summary of Orders and Documents Regarding Cost of Service, Minimum System, and Basic Customer Charges**

| Docket No. | Order Dated | | Notes |
|---|---|---|---|
| E-7, Sub 120 | February 12, 1971 | | No notable items on COSS, MSM, or BCCs |
| E-7, Sub 145 | June 21, 1973 | 1 | Noted an order requiring Duke to file a report on Cost of Service Study, dated September 28, 1970 in E-7 Sub 120. |
| | | 2 | FOF 22 cites minimum intercept method is more correct & stable than minimum size method. |
| | | 3 | Commission's E&C for "Rates" recognizes that the minimum customer cost is not covered by the charge for 100 kWh. However, Commission is reluctant to move it too much toward that goal (principle of gradualism). Commission approved using 80 kWh as the basis for the customer charge. |
| | | 4 | Requirement to file an annual COSS. Said study to include - demand data, size of distribution plant used to compute customer-related components of distribution system that will comply with NESC, cost of the sizes and regression associated with the minimum intercept method, and any changes noted from past COSSs. |
| E-7, Sub 161 & 173 | October 3, 1975 | 1 | Commission concluded that rate design should reflect the cost of electric service to customers, conserve energy resources, and promote economic efficiencies. (E&C for FOF 18) |
| | | 2 | Customer costs including billing costs, meters, service drop, and part of the distribution plant. Duke recovers these through a minimum bill and in the early block of energy rates. (E&C for FOF 18) |
| | | 3 | Introduces the basic facilities charge. Its set regardless of energy use to recover customer costs that are fixed. (E&C for FOF 18) |
| | | 4 | TOU and peak pricing to be reviewed in Docket E-100, Sub 21 beginning in Dec 1975. Demand growth in system peaks is happening. |
| S:/Floyd/E-7 Sub 145 Fully Distr Cost of Svc 1970 AND S:/Floyd/E-7 Sub 145 App to Author Adjustment of Rates 11.16.72 | | | Actual cost of service document dated December 1970 - Describes minimum size and minimum intercept methods and "skeleton" system. |
| E-2, Sub 193 | February 26, 1971 | 1 | FOF 3 notes that CP&L has started a 2 year COSS per October 2, 1970 order (Docket ???) |
| E-2, Sub 229 | January 6, 1975 | 1 | Rate design issues too numerous to discuss individually. (Summary item #5 or Order) |
| | | 2 | Commission denies increases in lower tiers of rates for residential and small and medium general service rates. These customers are not driving the need for increased revenues. |
| E-2, Sub 264 | February 20, 1976 | 1 | Most customer-related costs will be recovered in the a separate customer charge. (FOF 16) |
| | | 2 | COSS should be used as a guide in the setting of rates but not used as the sole determining factor in rate design. (p.110 Order) |
| | | 3 | Discussion in this order is similar to E-7 Sub 161 & 173 above. |
| E-2, Sub 297 | September 9, 1977 | 1 | Residential rate design proposed by CP&L is approved, except for the BCC, which should be decreased. (FOF 24) |
| | June 29, 1977 | | |
| E-2, Sub 526 | August 27, 1987 | 1 | SWPA COSS method and use of the minimum system method is appropriate. (FOF 8) |
| | | 2 | CP&L requested approval to discontinue using minimum system method. Request was denied. (E&C for FOF 8) |
| | | 3 | MSM allocates more distribution plant to residential customers and less to industrial customers and is conceptually sound even if the result of the MSM is not fully reflected in the BFC. Also, the MSM will modify the impact of SWPA on the industrial class. |
| E-2, Sub 537 & 333 | July 5, 1988 | 1 | Same language about COSS and MSM as the Sub 526 order above. |
| | | 2 | No change made to the BCC. (App. A of Order) |
| E-22, Sub 141 | June 28, 1973 | 1 | Prescribes the calculation of the MSM. |

I/A

Start Time : 04/04/2020 09:00:00 L1 : 04/04/2020 09:00:00
End Time : 04/05/2020 09:00:00 L2 : 04/05/2020 08:57:36, (L2 - L1) : 23:57:36

| | G | Point Name | Historian | Process | Description | End Value | Units | S | Low Scale | High Scale | Left Curso | Right Curs | Differe |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ☑ | (A) 08STDWATT.UNIT78@NET2 | Auto Historian | Actual | GENERATOR WATTS | 95.3 | MW | ☑ | 0 | 105 | 92.9 | 95.3 | 2.4 |
| | ☑ | (A) 08STIP_P.UNIT78@NET2 | Auto Historian | Actual | INLET PRESS FEEDBACK | 1777.00 | PSIG | ☑ | 0 | 3000 | 1744.91 | 1777.00 | 32.09 |
| | ☑ | (A) 08STTT_RHS.UNIT78@NET2 | Auto Historian | Actual | REHEAT STEAM TEMP | 1047.4 | DEGF | ☑ | 0 | 1200 | 1028.4 | 1047.4 | 19.0 |
| | ☑ | (A) 08STAP_P.UNIT78@NET2 | Auto Historian | Actual | 0 | 77.1 | PSIG | ☑ | 0 | 3000 | 77.1 | 77.1 | 0.1 |
| | ☑ | (A) 07GTJX0008.UNIT78@NET2 | Auto Historian | Actual | 7 GT MW | 185.4 | MW | ☑ | 0 | 250 | 187.0 | 185.4 | -1.6 |



# YOUNG REBUTTAL EXHIBIT NO. 1

MOODY'S
INVESTORS SERVICE

SECTOR IN-DEPTH
2 March 2020

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Regulated electric and gas utilities – US

# Grid hardening, regulatory support key to credit quality as climate hazards worsen

» **Heavy investment in infrastructure hardening to continue apace.** Climate change is likely to increase the frequency and severity of extreme weather events, which could pose potential threats to the financial performance of US investor-owned utilities. Infrastructure investments and regulatory support will be critical to maintain credit quality in the sector in the face of worsening climate hazards. Investments in the sector remain robust and we expect utilities to continue spending at peak levels, at least, over the next two years.

» **Extent and timing of regulatory support is key to managing near-term climate hazards.** The extent of the regulatory response and the speed at which a utility can secure approval for cost recovery subsequent to an extreme weather event will largely determine the degree of financial strain a utility experiences. Regulatory tools such as storm cost recovery provisions, decoupling mechanisms and securitization financing, are used to provide timely recovery and mitigate the financial impact from extreme weather events.

» **Efforts to encourage utilities to prepare for climate hazard contingencies in advance are credit positive.** Preemptive measures by regulators and legislators to shield utilities from the financial impact of future weather events should support credit quality ahead of an event. Regulators in several states, supported in some cases by newly enacted legislation, allow utilities to use storm reserves and have approved grid modernization spending plans to buffer against the financial impact of future weather events.

» **Regulatory support for recovery of infrastructure investments may weaken as rates rise.** While grid hardening and resiliency investments should go a long way in preparing utilities for future climate hazards, the costs will be typically borne by customers and will cause rates to rise. If extreme weather events occur frequently enough such that cost recovery through rate increases becomes onerous on customers, regulators may defer or deny future rate base investment recovery out of concern that rates are rising too much. This, in turn, could hinder a utility's future capital investment plans as well as its ability to add such investments to rate base and earn a return on them. When costs are an issue, securitization, a low cost of capital, can spread these costs over many years, which can mitigate the pressure of higher customer rates.

### Climate hazards that pose growing risks for utilities

Over the next 10 to 20 years, the risk of heat stress, water stress, extreme rainfall and flooding, and hurricanes is likely to worsen in certain regions of the US, according to data provided by Moody's affiliate Four Twenty Seven. These growing risks were the focus of our Sector In-Depth report, "Regulated electric utilities – US: Intensifying climate hazards to heighten focus on infrastructure investments."

**Heat stress**: Heat stress can impede thermoelectric power generation by reducing a power plant's cooling capacity; stress the grid with a higher number of peak demand days; and increase the risk of power curtailments, rolling brownouts or blackouts. Parts of the Midwest and southern Florida face the highest levels of heat stress.

**Water stress:** For electric utilities, water stress is generally credit negative because of the critical role that water plays in the economy and in cooling power plants. Utilities located in the Rocky Mountain states, the Colorado River region and California face the greatest uncertainty around the security of long-term water supplies.

**Extreme rainfall and flooding:** Extreme rainfall and flooding are expected to become more intense in many regions. Severe weather is the most frequent cause of major power outages in the US. However, the potential credit implications of flooding and extreme rainfall are tempered by supportive regulation and flood insurance.

**Hurricanes:** Along the East Coast and the Gulf of Mexico, critical infrastructure assets, such as large power plants and transmission substations, will be exposed to increasingly powerful hurricanes and severe storm surges.

## Heavy investment in infrastructure hardening to continue apace

Climate change is likely to increase the frequency and severity of extreme weather events, which could pose potential threats to the financial performance of US investor-owned utilities (see "Regulated electric utilities – US: Intensifying climate hazards to heighten focus on infrastructure investments"). Infrastructure investments and regulatory support will be critical to maintain credit quality in the sector in the face of worsening climate hazards.

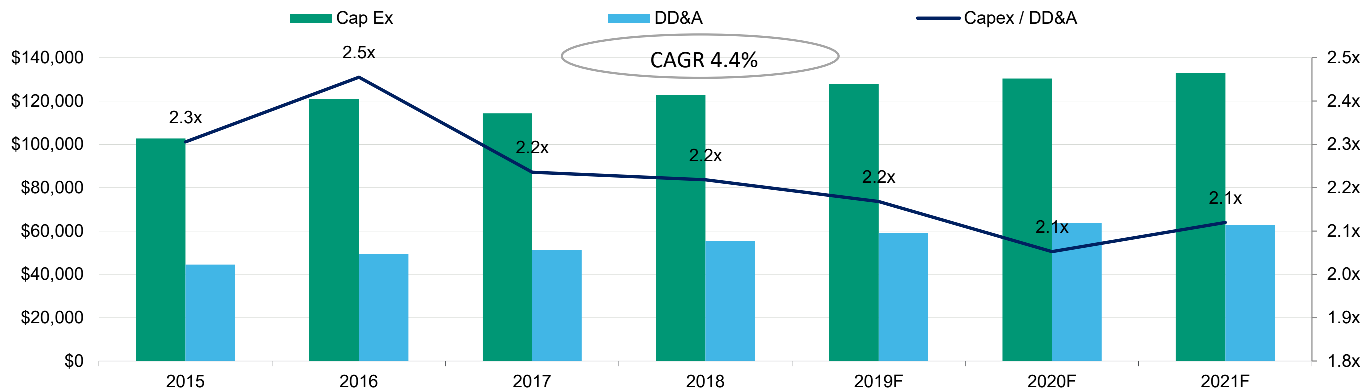
The utility sector continues to invest heavily in the face of flat to declining load and sales growth. Utilities have made steady investments to grow their rate base, partly to harden their systems against extreme weather events and to improve the resiliency of their operations. Investments in grid hardening and resiliency in advance of a climate hazard event will help mitigate the impact on customers, while also shortening recovery times. Moreover, a utility's preparedness could go a long way towards obtaining recovery of costs and investments deemed prudent by state regulators.

Investments in the sector remain robust and we expect utilities to continue spending at peak levels, at least, over the next two years. Capital spending has typically exceeded depreciation levels by more than twofold. We expect the ratio of capital spending to depreciation, depletion and amortization (DD&A) to be about 2.1x in 2020 and 2021, although lower than the peak of 2.5x in 2016. The majority of utility investments are typically recovered in customer rates upon approval by state regulators through a rate case filing. Because of the length of a rate case proceeding, utilities may experience regulatory lag – the interval between a utility's expenditures on costs and investments and their recovery from customers through an increase in rates – of up to a year or more. Regulatory adjustment mechanisms, such as riders and trackers, can provide for more timely recovery of investments. Investment recovery mechanisms are more supportive of a utility's credit quality if they are available in advance of extreme weather events rather than after.

Exhibit 1

**Utilities investment has remained slightly over two times annual DD&A, driving rate base growth**

**Annual ratio of aggregate capital expenditures to DD&A for 58 North American regulated utility holding companies ($ millions)**




Note: Exhibit from Moody's August 12, 2019 publication *"Regulated electric and gas utilities - North America_Free cash flow and capital allocation:external capital needs to decline in 2019"*
*Source: Moody's Financial Metrics, Moody's estimates, company presentations and SEC filings*

The experiences of San Diego Gas & Electric Company (SDG&E, Baa1 positive) and Florida Power & Light Company (FPL, A1 stable) demonstrate how investments in hardening an electrical system can sharply reduce a utility's vulnerability to the risk of wildfires or major storms.

In October 2007, SDG&E's equipment was found to have ignited the Witch, Guejito and Rice wildfires, which resulted in $2.4 billion in costs and legal fees related to third-party damage claims. SDG&E was able to recover the majority of these claims through its insurance coverage, costs allocated to Federal Energy Regulatory Commission (FERC) jurisdictional rates and settlement payments from third parties. However, the California Public Utilities Commission (CPUC) denied recovery of $379 million of these costs, concluding that the utility did not reasonably manage and operate its facilities prior to the fires.

Since then, SDG&E has invested $1.5 billion in fire risk mitigation efforts. Over that period, SDG&E has been the only one of California's three large investor-owned electric utilities not to experience a major wildfire in its service territory. From 2008 through 2018, SGD&E invested $15.3 billion in new capital, which far exceeded the company's $6.3 billion of plant depreciation, a proxy for maintenance capital investments. The $9 billion in growth capital invested over that time incorporated the $1.5 billion in fire risk mitigation efforts, which includes hardening high-risk wildfire and fire-prone areas, replacing wooden poles with steel poles, upgrading the older overhead electric distribution system, and undergrounding 10,000 miles of electrical lines, or 60% of SDG&E's electrical system. SDG&E's investments are generally recovered through its multi-year general rate cases, which incorporate forward test years, reducing the potential for regulators to disallow recovery on its capital spending.

Similarly, FPL has invested more than $3 billion since 2006 after severe hurricanes struck its service territory in 2004 and 2005. Over the ensuing 14-year period, FPL has invested over $48 billion in new capital, which is about 2.5x the amount of its $18.4 billion in depreciation expense over that time. FPL's investments were aimed at building an energy grid that is more resilient during major storms and shortening the time it would take to restore power after an outage. FPL has fortified transmission lines, replaced poles, and cleared vegetation from more than 150,000 miles of power lines. The utility has also made investments in smart grid technology, including nearly 5 million smart meters and more than 83,000 intelligent devices like automated feeder switches.

The improvement in FPL's storm resiliency is illustrated by the time it took the utility to restore power after two Category 5 hurricanes, one in 2005 and one in 2017. In the aftermath of Hurricane Irma in 2017, it took FPL just a day to restore electricity to half of its customers who had lost power, a sharp improvement from the five days it took to restore power to half of its customers who lost power after Hurricane Wilma in 2005. Furthermore, FPL restored power to all of its customers within 10 days after Irma, versus 18 days following Wilma.

We expect utilities in the Rocky Mountain states, the Colorado River region and California to continue to make investments to mitigate their exposure to the risk of water shortages. Berkshire Hathaway Energy Company (A3 stable) subsidiary PacifiCorp (A3 stable) outlined several steps in its 2019 integrated resource plan to reduce reliance on stressed water supplies including planned thermal plant retirements. Of the 24 coal-fired power units currently serving PacifiCorp customers, the utility plans to retire 16 units with a generating capacity of 2,800 MW by 2030 and 20 units with 4,500 MW of capacity by the end of 2038. PacifiCorp will seek recovery of any stranded costs and planned investments through its general rate case proceedings. The utility also plans to add nearly 11,000 MW of new renewable resources to its generation portfolio over its 20-year planning period through 2038 to supplement any lost generation from thermal plant retirements. Furthermore, the company's power plant designs include closed-cycle recirculating cooling water systems, and the company has developed a diversified water supply portfolio.

Southwestern Public Service Company (SPS, Baa2 stable), a subsidiary of Xcel Energy Inc. (Baa1 stable), is also facing water supply issues at its Tolk coal-fired facility in Texas. In its pending rate cases, SPS is requesting accelerated depreciation of its remaining investment in the plant in order to retire the plant early in 2032. The utility has expressed concerns about the rapid depletion of groundwater that it uses to cool the plant. SPS estimates that if it were to run the plant normally, the utility would run out of its groundwater rights by the mid-2020s. Thus, the company is seeking to limit steam-turbine generation largely to the peak summer months, which would allow SPS to extend the use of its groundwater rights until 2032. At the same time, SPS is heavily investing in renewable energy to maintain reliable service to its customers.

## Extent and timing of regulatory support is key to managing near-term climate hazards

The extent of the regulatory response and the speed at which a utility can secure approval for cost recovery subsequent to an extreme weather event will largely determine the degree of financial strain a utility experiences. Regulatory tools such as securitization, decoupling mechanisms and storm cost recovery provisions, are used to provide timely recovery and mitigate the financial impact from extreme weather events.

### Securitization

Securitization bonds were used after the deregulation of utilities in the late 1990s as a way to finance stranded costs. To date, more than 20 states have used this financing technique to recover not only stranded costs but also costs associated with storm recovery. To a lesser degree, utilities also use securitization for environmental restoration, utility restructuring, deferred fuel costs and renewable energy projects.

In June 2005, then-Florida Governor Jeb Bush signed a bill that gave the Florida Public Service Commission the authority to approve requests from the state's utilities to securitize storm recovery costs. Following Hurricanes Katrina, Rita and Wilma in 2005, Arkansas, Louisiana, Mississippi and Texas joined Florida in passing legislation giving utilities operating in these jurisdictions the option of utilizing securitization for recovery of storm costs.

We typically view the use of securitization as credit positive for utilities because they can issue bonds with lower financing costs that are paid back through a discrete customer charge (see "Regulated electric utilities – US: Utility cost recovery through securitization is credit positive"). A utility benefits from securitization because it receives an immediate source of cash. The ability to use securitization generally means that the utility is allowed to recover all or most of the costs in question in a timely manner. The utility's customers benefit because rates are lower than if the securitization was not utilized and in many cases it averts the need for a substantial rate increase. The ability to use securitization as a tool to recover costs related to large or unforeseen developments allows utilities to avoid potentially credit negative consequences.

I/A

Exhibit 2

**More than 20 states allow utilities to request securitization for the recovery of certain costs, which includes storm recovery costs in some states**

**US states with enacted or pending securitization legislation**

| State | Types of Use |
|---|---|
| Arkansas | Storm Recovery |
| California | Stranded Costs / Regulatory Asset / Wildfires |
| Colorado | Stranded Costs |
| Connecticut | Stranded Costs |
| Delaware | Undergrounding |
| Dist. of Columbia | Undergrounding |
| Florida | Storm Recovery / Nuclear Plant Retirement |
| Hawaii | Environmental / Clean Energy Technologies |
| Illinois | Stranded Costs |
| Louisiana | Storm Recovery / Stranded Costs |
| Massachusetts | Stranded Costs |
| Michigan | Stranded Costs |
| Mississippi | Storm Recovery |
| Montana | Stranded Costs |
| New Hampshire | Stranded Costs |
| New Jersey | Stranded Costs / Deferred Balances |
| New Mexico | Stranded Costs |
| New York | Debt Restructuring |
| North Carolina | Storm Recovery |
| Ohio | Deferred Balances |
| Pennsylvania | Stranded Costs |
| Rhode Island | Stranded Costs |
| Texas | Storm Recovery / Stranded Costs |
| West Virginia | Environmental / Deferred Balances |
| Wisconsin | Environmental |

*Source: Moody's Investors Service and company filings*

But even in states where utilities can ask to securitize recovery costs, regulators may not always allow it or do so in a timely manner. California Senate Bill 901, which was enacted in September 2018, allowed utilities affected by wildfires in 2017 to securitize fire-related recovery costs. Still, Pacific Gas & Electric Company (PG&E) did not expect the CPUC to permit the company to securitize costs relating to the 2017 Northern California wildfires on an expedited or emergency basis. Additionally, SB 901 did not authorize securitization with respect to costs related to 2018 wildfires, including the destructive Camp Fire. As such, the timing and uncertainty of wildfire cost recovery was one of the key factors that contributed to PG&E's bankruptcy filing. Coincidently, the CPUC has been requested to consider allowing PG&E to utilize securitization bonds as part of the company's plan of reorganization as PG&E attempts to emerge from bankruptcy by 30 June 2020.

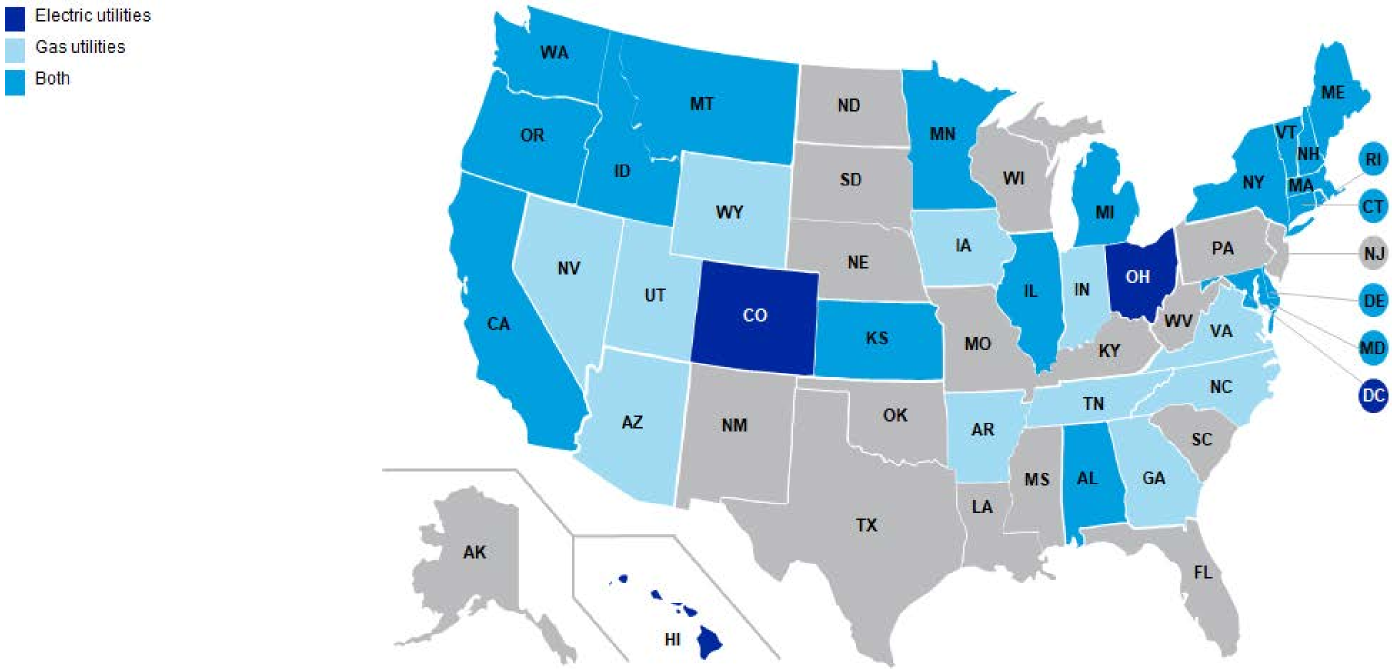
## Decoupling and other storm cost recovery mechanisms

Revenue decoupling is a ratemaking mechanism that is generally designed to eliminate or reduce the volatility of a utility's revenues on system throughput (i.e., electricity load or natural gas volumes). Decoupling mechanisms help insulate the credit quality of utilities to safeguard against the financial impact from a decline in electricity and natural gas consumption due to factors beyond the utility's control, such as energy efficiency, fluctuations in commodity fuel prices and weather. Decoupling is a widely used regulatory mechanism by natural gas local distribution companies (LDCs) throughout the country, but is becoming more prevalent for vertically integrated electric utilities and transmission and distribution companies. In 2012, after Superstorm Sandy caused the worst storm-related power outage in the history of Consolidated Edison Inc. (ConEd, Baa1 negative), the company's ample liquidity and supportive regulatory mechanisms, including revenue decoupling, mitigated the financial impact and insulated the utility's credit quality.

Exhibit 3

**Decoupling, widely used by LDCs, is becoming more prevalent among electric utilities**

**States with partial or full decoupling revenue recovery mechanisms for electric and gas utilities**




*Source: Moody's Investors Service, S&P Global Market Intelligence, Company filings*

Regulators in other jurisdictions affected by storms also allow their utilities to use storm cost recovery provisions to recoup storm related damages. The New York Public Service Commission allows Avangrid Inc.'s (Baa1 stable) New York utility subsidiaries, New York State Electric & Gas Corporation (A3 stable) and Rochester Gas and Electric Company (A3 stable), to utilize rate adjustment mechanisms to collect from customers, subject to a cap, eligible deferrals and costs related to major storms, property taxes, leak prone pipe and certain other costs. However, Avangrid has expressed concerns about the timely recovery of storm restoration costs for its New York utilities, which has been a drag on the company's cash flows. Over the past two years, the company's financial performance weakened, partly due to the costs associated with storm preparation and recovery, including staging activities ahead of potential storms, costs to restore power and overtime paid to utility workers. This, along with debt-funded capital spending has reduced Avangrid's ratio of cash flow from operations pre-working capital to debt to 16.7% for the 12 months ended 30 September 2019 from about 22% in full-year 2018.

Exhibit 4

**Select list of regulatory mechanisms that support utilities credit quality ahead of and after extreme weather events are common**

| Utilities | State | Mechanism | Primary Weather Mitigation | Brief Description |
|---|---|---|---|---|
| Alabama Power Company | AL | Rate NDR (Natural Disaster Reserve) | Storms | Comprised of two components: recovery of previously deferred storm costs; and establish a reserve for future storms. Allows for reserve of operations and maintenance expenses to cover the cost of damages from major storms to transmission and distribution facilities |
| San Diego Gas & Electric Company, Southern California Edison Company, Pacific Gas & Electric Company | CA | Wildfire Fund | Wildfires | Established a $21 billion wildfire insurance fund intended to improve the financial stability of utilities against growing liabilities associated with wildfires |
| Connecticut Light and Power Company | CT | Capital Tracker | Storms | Timely recovery of capital additions for system resiliency and grid modernization |
| Potomac Electric Power Company | DC | Undergrounding rider | Storms | Timely recovery of costs related to undergrounding certain electric power lines |
| Florida Power & Light Company, Duke Energy Florida, LLC, Tampa Electric Company, Gulf Power Company | FL | Storm Reserve | Storms | Reserve fund collected from customers up to a certain amount that can be used for timely cost recovery of damages related to tropical storms and hurricanes |
| Florida Power & Light Company, Duke Energy Florida, Tampa Electric Company, Gulf Power Company | FL | Storm Cost Recovery Rider | Storms | Electric utilities are provided a storm cost recovery mechanism, allowing them to petition the FPSC to recover costs incurred from storms that exceed and/or deplete their storm reserve and to replenish the reserve |
| Indianapolis Power and Light Company, Indiana Michigan Power Company, Duke Energy Indiana Company, LLC, Northern Indiana Public Service Company, and Southern Indiana Gas and Electric Company | IN | Rider | Storms | Timely recovery of costs associated with certain electric and gas infrastructure expansion projects, including grid modernization and reliability |
| Entergy New Orleans, LLC | LA | Storm Reserve | Storms | Reserve fund collected from customers up to a certain amount that can be used for timely cost recovery of damages related to tropical storms and hurricanes |
| Central Maine Power Company | ME | Storm Rider | Storms | Timely recovery of storm related costs |
| NSTAR Electric Company, Massachusetts Electric Company, Fitchburg Gas & Electric Light Company | MA | Rider | Storms | Timely recovery of grid modernization investments |
| Entergy Mississippi, LLC | MS | Storm Reserve | Storms | Reserve fund collected from customers up to a certain amount that can be used for timely cost recovery of damages related to tropical storms and hurricanes |
| Public Service Electric and Gas Company, Atlantic City Electric Company, Rockland Electric Company, New Jersey Natural Gas Company, Elizabethtown Gas Company, South Jersey Gas Company | NJ | Rider | Storms / Flooding | Timely recovery of investments related to storm hardening and reliability investment programs |
| New York State Electric and Gas Corporation, Rochester Gas & Electric Corporation, Central Hudson Gas & Electric Corporation | NY | Rate Adjustment Mechanisms/Storm Reserve | Storms | Adjusts customer rates and reserve fund used for timely recovery of costs related to several items including major storms |
| Ohio Power Company | OH | Rider | Storms | Timely recovery of investments made for enhanced service reliability and storm damage recovery |
| Oklahoma Gas & Electric Company | OK | Rider | Storms | Timely recovery of storm related costs |
| Entergy Texas, Inc. | TX | Storm Rider | Storms | Timely recovery of storm related costs |
| Virginia Electric and Power Company | VA | Undergrounding rider | Storms | Timely recovery of costs related to undergrounding certain electric power lines |

*Source: Moody's Investors Service, Company filings, S&P Global Market Intelligence*

## Ad hoc regulatory relief

Regulators also have the flexibility to provide utilities with relief from unexpected costs related to extreme weather events.

As we noted in our previous report, changes in precipitation patterns and other weather events, such as droughts and flooding, are likely to worsen over the next 10 to 20 years. Extreme rainfall and flooding, not limited to hurricanes, are expected to become more intense in many regions such as parts of the Midwest, Southeast and Pacific Northwest.

However, the potential credit implications of flooding and extreme rainfall are tempered by supportive regulation and flood insurance. In a possible preview of what's to come, FERC approved in October 2019 an increase in rates that Spire Inc. (Baa2 stable) subsidiary Spire STL could charge customers to cover increased construction costs related to heavy rain and flooding. Spire STL completed construction of an underground natural gas pipeline through Illinois and Missouri after a delay of several months because of flooding in the summer of 2019. As a result, construction costs for the project increased from an estimated $220 million to about $287 million.

## Efforts to encourage utilities to prepare for climate hazard contingencies in advance are credit positive

Preemptive measures by regulators and legislators to shield utilities from the financial impact of future weather events should support credit quality ahead of an event. Regulators in several states, supported in some cases by newly enacted legislation, allow utilities to use storm reserves and have approved grid modernization spending plans to buffer against the financial impact of future weather events.

In Florida, one of the more credit-supportive regulatory jurisdictions, the state's electric utilities are able to utilize several regulatory mechanisms to protect themselves from the financial impact of hurricanes and tropical storms. Utilities are allowed to accrue a reserve that can be drawn on to recover future storm costs. FPL's storm reserve accrual is up to $117 million, Duke Energy Florida LLC (A3 stable) received approval to replenish its storm reserve to $132 million, Tampa Electric Company's (A3 positive) storm reserve is $47 million and Gulf Power Company (A2 stable) has a $41 million reserve accrual. If a utility depletes its storm reserve or if its storm restoration costs exceed the reserved funds, it can request the Florida Public Service Commission to approve a surcharge on customer bills to recover storm costs and replenish the storm reserve for future use. When storm-related costs have been significant, Florida utilities have utilized securitization bonds to recover related costs, while also lessening the impact on customer rates.

Last year, Florida Governor Ron DeSantis signed into law Senate Bill 796, which requires utilities in the state to submit 10-year transmission and distribution storm protection plans on an annual basis. The plans are to detail the utility's efforts to further harden the grid and make it even more resilient during extreme weather events, like tropical storms and hurricanes. The legislation noted that “protecting and strengthening transmission and distribution electric utility infrastructure from extreme weather conditions can effectively reduce restoration costs and outage times to customers and improve overall service reliability for customers.” The law requires the Florida Public Service Commission to conduct an annual proceeding to review the plans and allow the utility to recover certain costs and investments that are deemed prudent. Costs would be recovered through a separate charge on customer bills rather than through base rates. This proactive law is credit positive for the state’s utilities, including FPL, Duke Energy Florida, Tampa Electric Company and Gulf Power because it allows them to grow rate base through increased investments and obtain timely recovery of these costs, all in an effort to ensure customer reliability and mitigate the risk of storm related outages (see “Regulated electric utilities – US: New Florida law requiring storm-hardening measures is credit positive for utilities”).

In July 2019, California Governor Gavin Newsom signed into law Assembly Bill 1054, which included several wildfire mitigation measures to support the financial stability of the state’s utilities, including Southern California Edison Company (SCE, Baa2 stable), SDG&E, and potentially PG&E, depending on the timing of its emergence from bankruptcy. The law included the establishment of a wildfire insurance fund to provide utilities with an immediate source of liquidity to cover potential liabilities caused by a wildfire ignited by their equipment when the damages exceed the utility's insurance coverage. Assuming that PG&E is able to participate and contribute, the fund will be capitalized to a total of $21 billion or fall to about $9.6 billion without PG&E's participation (see “Regulated electric and gas utilities – US: California's wildfire fund is sufficiently capitalized to pay out claims”).

A number of factors contribute to the growing size and destructive power of California wildfires, including climate change and population growth in fire-prone areas. California's utilities are particularly vulnerable to the financial impact of utility-related wildfires because the state's application of the legal doctrine of inverse condemnation law holds utilities liable for wildfire damages if their equipment is found to be the source of ignition or has somehow caused the fire, regardless of fault or the reasonableness of their conduct. AB 1054 establishes a strong framework to manage wildfire risk and the ensuing financial threats to the state's utilities but there is more work to be done. Effective implementation of the utilities' wildfire mitigation plans required under the law will be critically important to reduce wildfire-related risks.

In an effort to reduce the risk of future natural disasters, including wildfires, Nevada Governor Steve Sisolak signed into law Senate Bill 329 in May 2019. The new bill requires the state, its regulators and investor-owned and public utilities to devise natural disaster plans to reduce the frequency and intensity of wildfires by taking such preventative measures as adopting new forest management practices, increased vegetation trimming, and hardening of electric utility infrastructure. NV Energy Inc. (Baa2 stable) is seeking the approval of the Nevada Public Utilities Commission for its plan to recover costs related to the development and implementation of its natural disaster plan through a separate rate rider on customer bills.

Exhibit 5

**Select list of proactive regulatory and legislative measures mitigate credit risk**

| State | Utilities | Mechanism/Law | Climate Hazard | Brief Description |
|---|---|---|---|---|
| California | San Diego Gas & Electric Company, Southern California Edison Company, Pacific Gas & Electric Company | AB 1054 | Wildfires | Establishes a wildfire fund to provide the state's investor-owned utilities with an immediate source of liquidity to cover wildfire-related damages caused by a wildfire ignited by the utility's equipment when the damages exceed the utility's insurance coverage; liabilities not recovered from customers are capped at 20% of the equity portion of the utility's transmission and distribution rate base over any three-year period; and more favorable prudency standard for utilities to recover wildfire-related costs from customers |
| District of Columbia | Potomac Electric Power Company | Infrastructure Improvement Financing Act ("ECIIFA") of 2014 | Storms | Allows for timely recovery of costs related to undergrounding certain electric power lines through a separate charge on customer bills |
| Florida | Florida Power & Light Company, Duke Energy Florida, LLC, Tampa Electric Company, Gulf Power Company | SB796 | Hurricanes, storms | Requires utilities to submit, on an annual basis, an infrastructure storm protection plan that covers the following 10 years. Regulators will review the plan and authorize recovery of prudent costs through a separate charge on customer bills. |
| Nevada | NV Energy Inc. | SB329 | Natural disasters, including wildfires | Requires utility submission of natural disaster protection plan to the commission and authorizes recovery through a separate rate rider. |
| New Jersey | Public Service Electric and Gas Company | Energy Strong Adjustment Mechanism (ESAM) | Storms | Regulators authorized utility investment program that was intended for grid hardening and system resilience against storms and allow timely recovery of costs. |

*Source: Moody's Investors Service and company filings*

In 2013, in the aftermath of Superstorm Sandy, the New Jersey Board of Public Utilities (BPU) initiated a storm mitigation proceeding in an effort to find ways to protect utility infrastructure during major storms. In May 2014, Public Service Electric and Gas Company (PSE&G, A2 stable) received approval of its $1.2 billion "Energy Strong" program, which it had submitted in response to the proceeding. Under the program, PSE&G protected, raised, or relocated 26 switching stations and substations; replaced and modernized 240 miles of gas mains in or near flood areas; created redundancy in the electric system; protected five natural gas metering stations and a liquefied natural gas station located in flood zones; and deployed smart grid technologies to better monitor electric system operations.

The BPU approved base rate adjustments to enable PSE&G to recover $1 billion in investments that the utility had made under its Energy Strong program, with the remainder recovered in the utility's 2018 rate case proceeding. The rate adjustments allowed PSE&G to recover major capital investments with respect to asset hardening and system resilience in a timely manner, as customer rates were adjusted at predetermined intervals to reflect expenditures incurred on the Energy Strong program from 2015 - 2019. In September 2019, the BPU approved an $842 million Energy Strong II program, albeit scaled back from PSE&G's $2.5 billion original proposal, which is intended to further harden the utility's system through investments made during 2019-2023.

In 2017, the District of Columbia enacted legislation to authorize the District of Columbia Power Line Undergrounding (DC PLUG) initiative, a projected six-year, $500 million project allowing Potomac Electric Power Company (Pepco, Baa1 stable) to move some of the district's most outage-prone power lines underground, with the costs funded by Pepco through a charge on customer bills as well as the District Department of Transportation. Pepco began construction in 2019 as new customer rates for the DC Plug initiative went into effect in February 2018.

## Regulatory support for recovery of infrastructure investments may weaken as rates rise

While grid hardening and resiliency investments should go a long way in preparing utilities for future climate hazards, the costs will be typically borne by customers and will cause rates to rise. If extreme weather events occur frequently enough such that cost recovery through rate increases becomes onerous on customers, regulators may defer or deny future rate base investment recovery out of concern that rates are rising too much. This, in turn, could hinder a utility's future capital investment plans, as well as its ability to add any such investments to rate base and earn a return on them. When costs are an issue, securitization can spread these costs over many years, which can mitigate the pressure on customer rates.

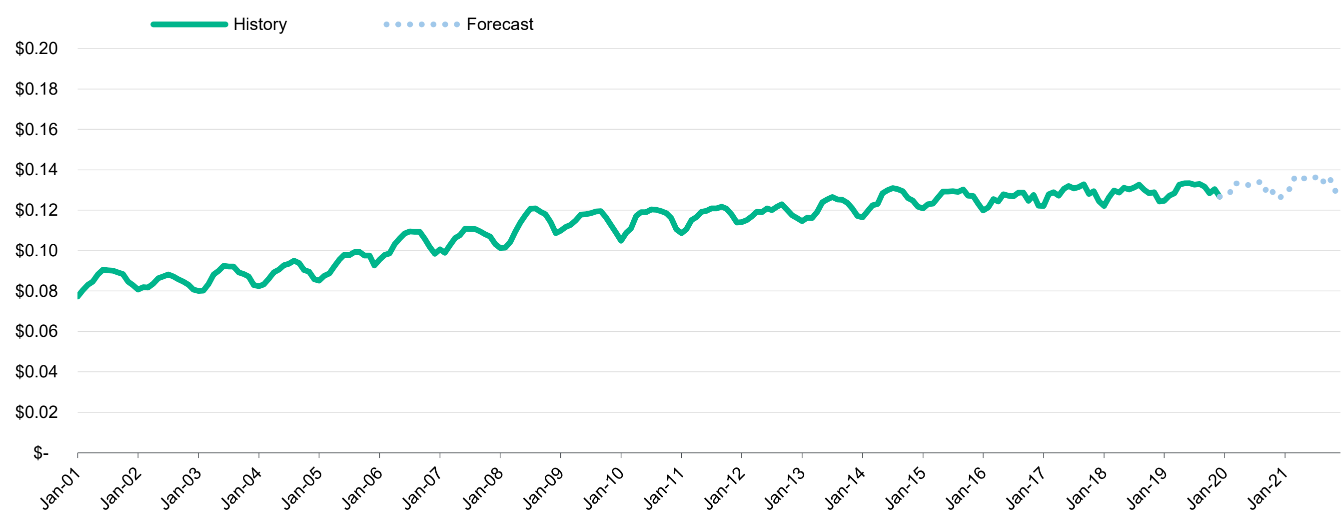
Over the next two years, we expect customer rates to remain relatively steady despite continued elevated spending. Lower tax expenses recovered from customers through the implementation of the 2017 Tax Cuts & Jobs Act, as well as continued low natural gas prices, has created revenue "headroom" in customer bills that utilities use to recover other costs and investments (see "Regulated electric and gas utilities – US: 2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics").

Similarly, the US Energy Information Administration (EIA) forecasts that the US residential retail electricity price will average 13 cents/kilowatt hour in 2020, which is 1.2% higher than the average retail price in 2019. EIA also projects residential prices to increase by an additional 1.2% in 2021.

Exhibit 6

**Residential electricity are projected to be only modestly higher in the near term**

**US residential retail electricity prices (cents per kilowatt/hour)**




*Source: US Energy Information Administration*

## Moody's related publications

### Sector In-Depth

» Regulated electric utilities – US: Intensifying climate hazards to heighten focus on infrastructure investments, January 2020

» Electric utilities and power producers – US: Power companies on pace to reduce CO2 emissions, September 2019

» Utilities and power companies – North America: Corporate governance assessments show generally credit-friendly characteristics, September 2019

» Regulated electric and gas utilities – US: Recent regulatory, legislative developments have been largely credit positive, September 2019

» Regulated electric and gas utilities - North America: Free cash flow and capital allocation: external capital needs to decline in 2019, August 2019

» Regulated electric utilities – US: FAQ on the credit implications of California's new wildfire law, August 2019

» Power generation – US: Nuclear zero emission credits reduce carbon transition risk but change market dynamics, June 2019

» Power generation – US: FAQ on the economics of renewable energy, battery storage and fossil-fuel power plants, June 2019

» Electric and Gas Utilities - US: California utilities struggle with inverse condemnation exposure, April 2019

» Regulated Electric & Gas Utilities - US: Capital expenditures will remain high, thanks to regulatory recovery mechanisms that provide timely recovery, December 2018

» Regulated Electric and Gas Utilities - US: Climate-related disclosures by four major utilities vary in both depth and scope, December 2018

» Regulated Electric & Gas Utilities - US: LDC Utilities Exposed to Operational Hazards, But Sector Still Viewed as Low Risk, November 2018

» Regulated Electric and Gas Utilities - US: Renewable generation transition unlikely to create significant stranded asset risk, November 2018

» Regulated electric and gas utilities - US: Cyber risk is on the rise, but the likelihood of government relief is high, September 2018

» Power generation - US: Coal, nuclear plant closures continue CO2 decline but power market impact muted, June 2018

### Sector Comments

» Regulated electric utilities – California: Customer bill credits after power shutoffs signal weakening political support, October 2019

» ESG - California: Public safety power shutoffs highlight links between environmental and social risks, October 2019

» Regulated electric utilities – US: Proposed California wildfire risk legislation is credit positive but questions remain, July 2019

» Regulated electric utilities – US: New Florida law requiring storm-hardening measures is credit positive for utilities, July 2019

### Industry Outlook

» Regulated electric and gas utilities – US: 2020 outlook moves to stable on supportive regulation, weaker but steady credit metrics, November 2019

REPORT NUMBER 1211706

I/A

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MOODY'S
INVESTORS SERVICE

# YOUNG REBUTTAL EXHIBIT NO. 2

## Exhibits to Steve Young Testimony

### 1. P/E Ratios as of April 24, 2020:

| Ticker | Company Name | Market Cap ($M) | Closing Price | 2021 EPS est. | 2021 P/E |
|---|---|---|---|---|---|
| **DUK** | **Duke Energy Corporation** | **62,899** | **85.69** | **5.45** | **15.7x** |
| **Daily Stock Report Peers** | | | | | |
| AEP | American Electric Power Company Inc. | 41,185 | 83.23 | 4.64 | 17.9x |
| ED | Consolidated Edison, Inc. | 27,600 | 82.64 | 4.59 | 18.0x |
| D | Dominion Energy, Inc. | 65,297 | 77.92 | 4.63 | 16.8x |
| ES | Eversource Energy | 28,597 | 86.57 | 3.90 | 22.2x |
| SO | Southern Company | 61,021 | 57.73 | 3.31 | 17.5x |
| WEC | WEC Energy Group Inc. | 29,578 | 93.77 | 3.99 | 23.5x |
| XEL | Xcel Energy | 33,901 | 64.57 | 2.96 | 21.8x |
| **Avg Large-cap Regulated Peers** | | | | | **19.7x** |
| | | | | **Discount** | **-4.0x** |

*Source: Factset*

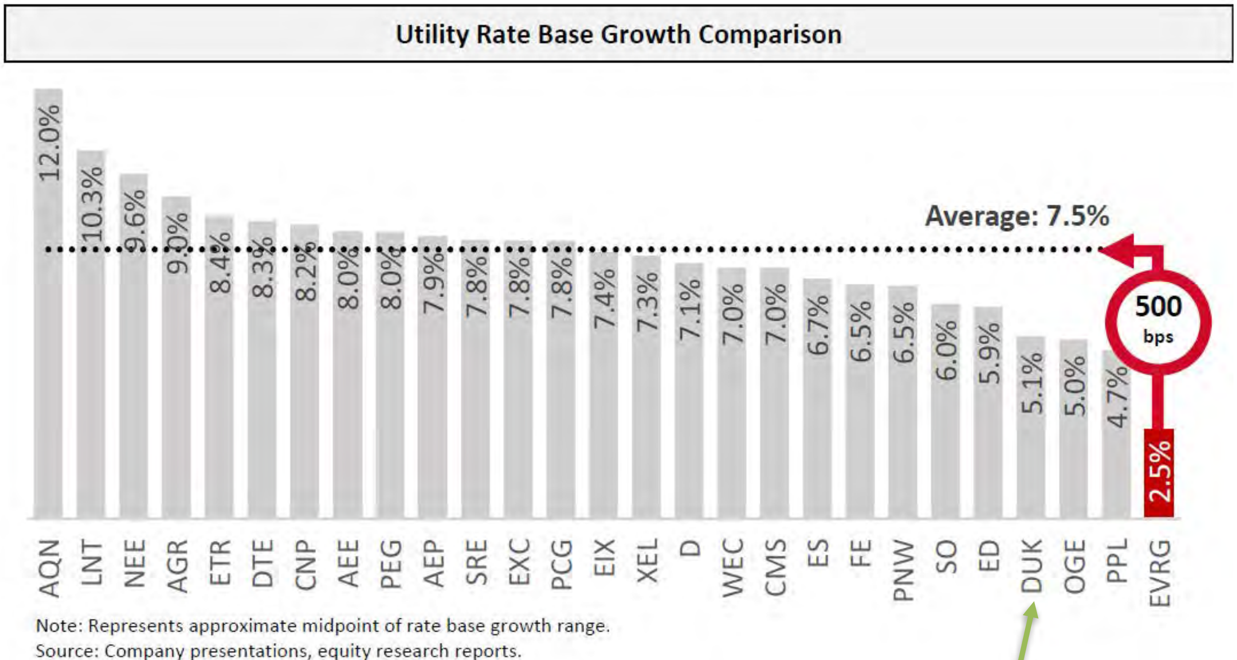
**As of Friday, April 24, 2020, DUK trades at a (20.3%) discount compared to large regulated peers (4.0/19.7 P/E).**

### 2. Stated long-term EPS growth rates:

| Ticker | | LT EPS Growth Rate |
|---|---|---|
| **DUK** | **Duke Energy Corporation** | **4 -6%** |
| **Daily Stock Report Peers** | | |
| AEP | American Electric Power Company, Inc. | 5% to 7% |
| ED | Consolidated Edison, Inc. | 3% to 5% |
| D | Dominion Energy Inc | 5%+ |
| ES | Eversource Energy | 5% to 7% |
| PCG | PG&E Corporation | N/A |
| SO | Southern Company | 4% to 6% |
| WEC | WEC Energy Group Inc | 5% to 7% |
| XEL | Xcel Energy Inc. | 5% to 7% |

*Source: company filings*

**3. Utility Rate base growth comparison**




source, Elliott letter to Evergy Management

Duke Energy has one of the lowest rate base growth rates despite operating in some of the fastest growing communities in the country.

# YOUNG REBUTTAL EXHIBIT NO. 3

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
13 October 2019

Update

Rate this Research

RATINGS

**Duke Energy Corporation**

| | |
|---|---|
| Domicile | Charlotte, North Carolina, United States |
| Long Term Rating | Baa1 |
| Type | LT Issuer Rating - Dom Curr |
| Outlook | Stable |

*Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.*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# Duke Energy Corporation

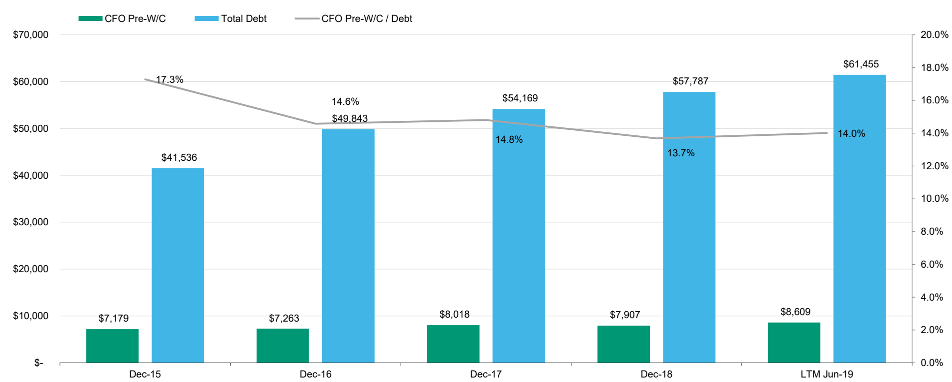
## Update to credit analysis

## Summary

Duke Energy Corporation (Duke) is one of the largest utility holding companies in the US. Its credit profile reflects the company's diverse, low business risk operations in which about 97% of earnings and cash flow are derived from rate regulated businesses in growing economies with supportive regulators. These credit supportive factors are balanced against weak financial metrics that we expect will improve somewhat in 2019, but dip again in 2020 before rebounding in 2021.

Exhibit 1

**Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($MM) [1]**




[1] CFO Pre-WC is defined as cash flow from operations excluding changes in working capital
*Source: Moody's Financial Metrics*

## Credit strengths

» Diverse group of utilities operating in seven states in three geographic regions

» Credit supportive regulatory relationships

» Businesses are essentially all regulated or contracted

» Approved recovery of the majority of coal ash related expenditures

## Credit challenges

» Weak consolidated credit metrics

» Significant, primarily debt financed, capital program

» Lag in the recovery of storm related costs and coal ash remediation spending

» Increasing regulatory uncertainty surrounding coal ash cost recovery

» Delays and cost increases at Atlantic Coast Pipeline (ACP) project

» Relatively high parent company debt levels

## Rating outlook

The stable outlook reflects our expectation that Duke will maintain supportive regulatory relationships in all of its jurisdictions. The outlook also assumes management will manage its operating, capital and financing plans in a manner that supports credit quality and enables the maintenance of credit metrics that are consistent with our expectations. For example, we anticipate the company's ratio of cash flow from operations excluding working capital (CFO pre-WC) to debt will improve to the 15% range.

## Factors that could lead to an upgrade

» Ratings could be upgraded if regulatory environments were to become more supportive, leading to increased cash flow and reduced leverage, and if the ratio of CFO pre-WC to debt can be maintained above 18%.

## Factors that could lead to a downgrade

» A deterioration in the credit supportiveness or emergence of a more contentious regulatory relationship which negatively impacts cash flows or the timeliness of cost recovery, particularly with regards to coal ash remediation recovery in North Carolina

» A ratio of CFO pre-WC that we expect to remain below 15% beyond 2020, or an increase in parent company debt levels above 35% of total consolidated debt

## Key indicators

Exhibit 2

**Duke Energy Corporation [1]**

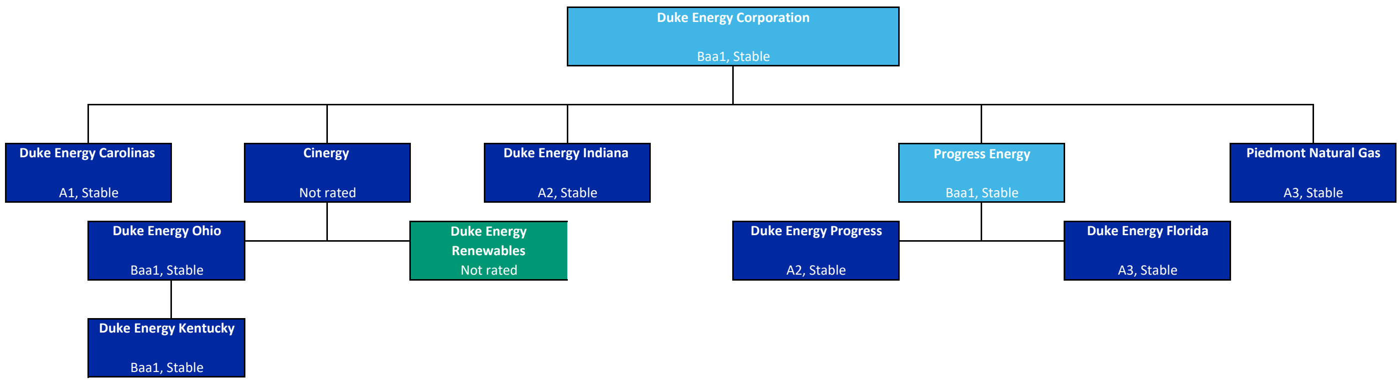
| | Dec-15 | Dec-16 | Dec-17 | Dec-18 | LTM Jun-19 |
|---|---|---|---|---|---|
| CFO Pre-W/C + Interest / Interest | 5.3x | 4.7x | 4.7x | 4.4x | 4.6x |
| CFO Pre-W/C / Debt | 17.3% | 14.6% | 14.8% | 13.7% | 14.0% |
| CFO Pre-W/C – Dividends / Debt | 11.8% | 9.9% | 10.3% | 9.4% | 9.8% |
| Debt / Capitalization | 44.2% | 47.5% | 53.0% | 52.9% | 53.6% |

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
*Source: Moody's Financial Metrics*

## Profile

Duke is a large (2018 revenues of $24.5 billion), diversified energy company with mostly regulated utility operations headquartered in Charlotte, North Carolina. Its main business consists of its electric utilities and infrastructure business segment, which serves approximately 7.7 million retail electric customers in six US states and made up about 90% of Duke's 2018 earnings base. The company's gas utilities and infrastructure businesses provide natural gas to over 1.6 million customers located in five states. Duke has also formed a joint venture to build and own a 47% share of the estimated $7.0-$7.8 billion Atlantic Coast Pipeline, a 600-mile interstate natural gas pipeline from West Virginia to the Carolinas which has been experiencing permitting delays and increased costs. The company's relatively small (about 3% of 2018 adjusted earnings) commercial renewables business segment builds, develops and operates wind and solar generation projects throughout the continental US.

Exhibit 3
**Duke Organizational Structure**




*Source: Moody's Investors Service, Company*

## Detailed credit considerations

### Diverse group of utilities operating in credit supportive regulatory environments

Duke's overall credit profile is driven by seven regulated utilities operating in seven US states, which provide a high degree of regulatory and geographic diversity. We consider these regulatory jurisdictions to be supportive with rate settlements in place at most of its utilities. In addition, the company has achieved reasonably credit supportive outcomes in its major jurisdictions on issues related to the majority of its coal ash remediation spending and federal tax reform.

In Duke's largest electric jurisdiction, North Carolina, the North Carolina Utilities Commission (NCUC) issued orders in 2018 for both Duke Energy Carolinas and Duke Energy Progress (combined approximately 56% of Duke's 2018 regulated earnings base) that established revenues based on a 9.9% return on equity, and a 52% equity base. The orders followed settlement agreements on traditional rate making parameters. We view the ability to regularly settle on more traditional issues as a credit positive.

The North Carolina orders also resolved issues relating to the recovery of costs for coal ash remediation. Spending for coal ash remediation has been deemed reasonable and prudent and, with the exception of a specific manageable penalty assessed in each case, the companies have been authorized to recover their prior expenditures over five years with a full debt and equity return. Ongoing expenditures will continue to be deferred for future recovery. We view the ability to earn a full return on these expenditures, and to recover them over reasonable time frames, as credit positive. As a result of this rate base like treatment, we currently view the spending for coal ash remediation to be akin to a capital expenditure.

In 2018, the NCUC also addressed the impact of federal tax reform. During the year, both Duke Energy Carolinas and Duke Energy Progress' revenue requirements were reduced by the full amount of the change in tax rate to 21% from 35%. However, the utilities were allowed to retain all excess deferred taxes for three years, or until its next rate case, whichever is sooner. At that time, the NCUC will evaluate how to best return this value to customers. We believe the form of return could include accelerated recovery of certain expenses, or the avoidance of rate increases. We would view such outcomes as credit positive.

The NCUC did however deny Duke's requests for rider recovery for grid modernization investments and ongoing coal ash remediation, both credit negatives. As a result, there will continue to be regulatory lag associated with these expenditures and we expect the utilities will need to file frequent rate cases to minimize this exposure. Duke has been working with lawmakers in an attempt to pass legislation that would allow securitization of storm costs as well as the consideration of alternative rate adjustment mechanisms such as rider recovery, multiyear plans, incentive mechanisms or ROE bands. Last week, a North Carolina conference committee produced a compromise bill that would authorize securitization of storm costs immediately, but would delay the implementation of alternative rate plans until 2021. The bill was immediately approved by the Senate and must now be approved by the House before heading to the Governor. A vote in the House is expected in October. Our stable outlook assumes a continuation of regulatory outcomes that will allow the companies to maintain cash flow based credit metrics at levels that are supportive of their current credit quality.

In South Carolina, in May 2019, the Public Service Commission of South Carolina (PSCSC) issued an order for rate increases at Duke Energy Carolinas and Duke Energy Progress for $107 million and $41 million respectively based on a 9.5% ROE and a 53% equity ratio. New rates were effective June 1, 2019. In a credit negative development, the PSCSC denied the recovery of certain coal ash costs deemed to be related to the North Carolina Coal Ash Management Act and incremental to the federal Coal Combustion Residuals rule in the amount of $115 million and $65 million at Duke Energy Carolinas and Duke Energy Progress respectively. In May 2019, both Duke subsidiaries filed a petition for rehearing or reconsideration of the PSCSC's order contending substantial rights of Duke Energy Carolinas and Duke Energy Progress were prejudiced by unlawful, arbitrary and capricious rulings by the commission on certain issues, including its ability to fully recover its coal ash remediation spending. In June 2019, the PSCSC issued a directive denying the company's request for rehearing. Duke Energy Carolinas and Duke Energy Progress are currently awaiting the written order detailing the PSCSC's decision and are prepared to appeal portions of the case to the South Carolina Supreme Court. Depending on the outcome of the appeal, we may modify our treatment of the portion of expenditures that are not recoverable.

In Florida (approximately 18% of 2018 regulated earnings base), as part of a 2017 second revised and restated settlement agreement (which amended a 2013 settlement agreement), Duke Energy Florida will increase base rates by an incremental $67 million (subsequently adjusted to $55 million to reflect the effects of federal tax reform) each year from 2019 through 2021, subject to an ROE range of 9.5% to 11.5%. The order also included provisions that addressed the expected passage of federal tax reform and included the ability to use a portion of future benefits resulting from lower tax rates to accelerate the depreciation of existing coal plants rather than decreasing revenue. In January 2018, the Florida Public Service Commission authorized Duke Energy Florida to utilize the remainder of the benefits of lower tax rates to avoid a rate increase for power restoration costs associated with the company's 2017 response to Hurricane Irma. In June 2019, the FPSC approved the company's request to recover approximately $221 million of incremental operating costs incurred as a result of Hurricane Michael. We view the ability to utilize tax reform savings to offset storm costs as a credit positive. Approved storm costs are currently expected to be fully recovered around year-end 2022.

Duke Energy Florida also continues to benefit from a credit positive Generation Base Rate Adjustment (GBRA) mechanism for new generation built or purchased during 2016-2018 that allows recovery of prudently incurred costs through a base rate adjustment when the generation is placed in service. Duke Florida's 1,640 MW $1.5 billion Citrus County combined cycle plant was placed into service in 2018. The 2017 settlement included a similar mechanism for up to 700MW of new solar generation to be acquired or constructed between 2018 and 2022.

In Indiana (about 11% of 2018 regulated earnings base), in June 2016, the Indiana Utility Regulatory Commission (IURC) approved a settlement agreement between Duke Energy Indiana and key consumer groups on a seven year $1.4 billion grid modernization plan. As a result, in accordance with previously approved state legislation, 80% of the plan's costs will be recovered through a rate rider, with the remaining 20% recoverable through future base rate proceedings. In May 2017, Duke Energy Indiana received approval to recover 60% of the capital and 80% of the operating costs of complying with the US Environmental Protection Agency's Coal Combustion Residuals rules via an environmental mandate tracker, and to defer the remaining difference for recovery in the utility's next rate case. In June 2018, Duke Energy Indiana reached a settlement with key intervenors on tax reform. The settlement calls for a flow through of the reduction in tax rate to 21% from 35% beginning in September. However, the protected portion of excess deferred taxes will be retained until January 2020, after which it will be returned over approximately 26 years. The unprotected portion will be returned over 10 years, but to mitigate the impact on cash flow based credit metrics, the amount is lower in the first five years.

In July 2019, Duke Energy Indiana filed a request for a $395 million (approximately 15%) base rate increase premised on a 10.4% return on equity and a 53% equity component. This is Duke Energy Indiana's first base rate case filing in 16 years and is being driven by capital investments in generation, improvements in the grid to ensure reliability and a growing customer base. The request includes $138 million relating to a change in depreciation, primarily to accelerate the retirement of certain coal-fired units. The company is also requesting the use of a forward test year, which was authorized by law in 2013. Duke expects hearings to begin in early 2020 with new rates effective by mid 2020.

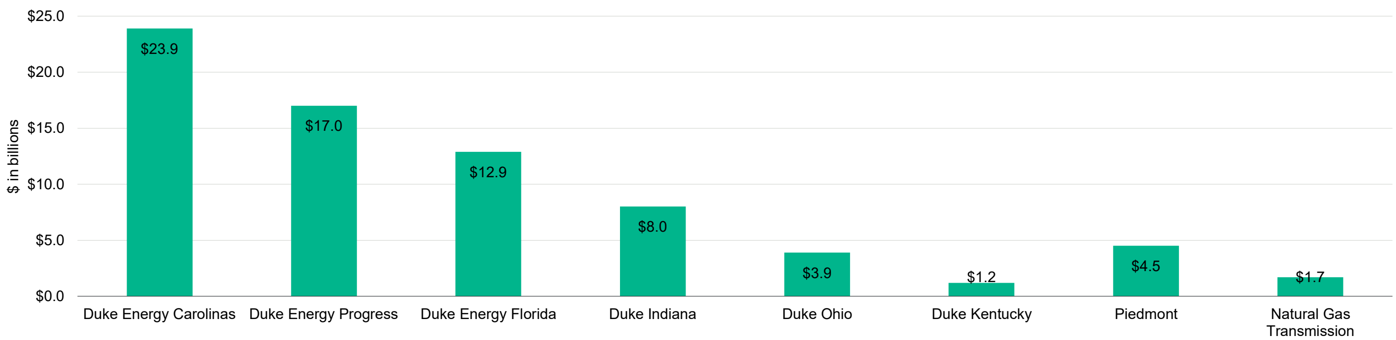
On the natural gas side, Duke's local gas distribution subsidiary Piedmont Natural Gas (Piedmont), has historically received supportive treatment from its regulators in North Carolina (73% of rate base), South Carolina (14%) and Tennessee (13%). In addition, all three states provide cost recovery mechanisms and frameworks that lead to reduced regulatory lag.

In August 2019 Piedmont reached a settlement agreement with the NCUC public staff for a base rate increase of approximately $109 million, after the expiration of various rider credits to flow back federal and state income tax credits. The agreed increase was based on a 9.7% ROE and a 52% equity layer. Piedmont initially requested an increase of $83 million (net of $37 million of reductions due to lower tax rates), based on a 10.6% ROE and a 52% equity layer. The settlement allows continuation of an integrity management rider for federally mandated safety and capital investments and establishes a new distribution integrity management program recovery mechanism. The settlement is subject to the review and approval of the NCUC.

## Operations are essentially all regulated

In 2015, Duke successfully exited the merchant generating business with the sale of Duke Energy Ohio's competitive generating assets. In 2016, Duke sold its more volatile Latin American businesses and acquired Piedmont Natural Gas Company (Piedmont), expanding its relatively low risk local natural gas distribution operations in the historically credit supportive states of North Carolina, South Carolina and Tennessee. As a result, essentially all of its operations are now either state or federally regulated. Duke's commercial renewables segment provides services under long term contracts, and contributed under 5% of the company's 2018 earnings. The shift to lower business risk operations has helped to mitigate the decline in credit metrics that followed the Piedmont acquisition.

Exhibit 4
**2018 Regulated Utilities Earnings Base**




*Source: Company*

## Consolidated financial credit metrics are weak

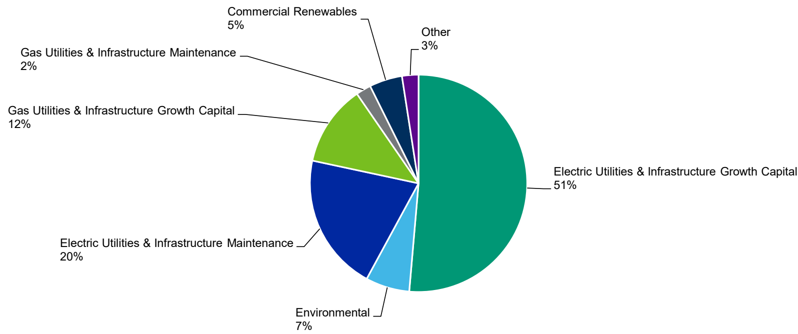
Duke's revenues and cash flow are being negatively impacted by the 2017 Tax Cuts and Jobs Act (TCJA), continued lag in recovery of coal ash remediation costs, severe storm activity, and lag in recovery of grid modernization investments. As a result, cash flow based credit metrics, which declined in 2016 following Duke's acquisition of Piedmont, have remained below our financial metric downgrade triggers. For example, for the last twelve months ended June 30, 2019, we calculate Duke's ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt to be about 14%, which is at the lower end of the "Baa" scoring range for this metric in our rating methodology for regulated electric and gas utilities and below our financial metric downgrade trigger of 15%. Absent the impact of the 2018 storms, we estimate the company's twelve month trailing ratio of CFO pre-WC to debt would be about 15%.

While we anticipate Duke's ratio of CFO pre-WC to debt will be around 15% for full year 2019, we believe it could fall toward 14% in 2020 before rebounding in 2021 as a result of rate case activity, operational enhancements, and lower dividend growth. In addition to planning regular rate cases in the Carolinas, Duke is also actively working with lawmakers on legislation that would allow the securitization of storm costs as well as alternative rate mechanisms that could reduce the lag in recovery, and would be credit positive. Our stable outlook assumes management will remain focused on achieving and maintaining a ratio of CFO pre-WC to debt in the 15-16% range, and that the metric will move into this range by 2021.

## High capital spending for utility infrastructure and growth initiatives

Capital expenditures at Duke, inclusive of spending for coal ash remediation, have steadily increased year over year, nearly doubling from about $5.5 billion in 2014 to about $10.1 billion in 2018. As shown in the exhibit below, the largest portion of the plan represents what Duke terms "growth" capital driven by grid modernization in the Carolinas and natural gas infrastructure. In 2018, maintenance spending increased to $3.2 billion due in part to restoration efforts related to storm damages; going forward maintenance spending is expected to range between $2 and $2.5 billion per year.

Exhibit 5
**2019-2023 Capital Expenditures Forecast ($50 Billion)**




*Source: Company*

In addition to its core utility investment, Duke is growing its natural gas pipeline businesses and plans to continue to selectively invest in renewables. Included in the company's capital plan for 2019-2023 is about $2.9 billion for midstream pipelines, primarily the Atlantic Coast Pipeline (ACP), and about $2.5 billion for utility scale contracted renewables. Although we view the commercial renewables business as higher risk than its regulated utility business segment, these assets for the most part sell power to investor owned, cooperative, or municipal utilities under risk mitigating long-term contracts. Duke recently sold a minority share in its commercial renewables portfolio, generating pre-tax proceeds of approximately $415 million, which will likely also reduce the future capital needs of this segment.

## Delays and cost increases at Atlantic Coast Pipeline (ACP) project

ACP is a 600-mile interstate natural gas pipeline being built by Dominion Energy, Inc. (Baa2 stable) from West Virginia to eastern North Carolina. Duke holds a 47% share in the project. The pipeline will supply natural gas from the Utica and Marcellus shale basins to natural gas generation at Duke Energy Carolinas and Duke Energy Progress, as well as to Piedmont and other utilities in the area.

Construction of ACP has been halted due to adverse court rulings on environmental issues, including a biological opinion and a permit to cross under the Appalachian Trail. As a result, the estimated cost to complete the project increased by about $1 billion, and its estimated completion schedule was extended by over a year. The pipeline is currently expected to cost between $7 and $7.8 billion ($3.3-$3.7 for Duke) and could be completed in two phases. Construction of the first phase, which does not cross the Appalachian Trail, could be restarted by year-end if there is a successful re-issuance of its biological opinion.

Construction of the second phase requires resolution of a Fourth Circuit Court of Appeals decision to vacate the permit issued by the U.S. Forest Service allowing ACP to cross under the Appalachian Trail. ACP has appealed the decision to the U.S. Supreme Court and just recently learned the Court has accepted the case. A decision is required by June 2020, which if favorable, would allow construction to begin next summer and the pipeline to be completed by the end of 2021. The increased costs, and delay of cash flow from this project, are maintaining downward pressure on Duke's credit metrics.

## Lag in the recovery of storm related costs will pressure metrics in the near term

In the fall and winter of 2018, Duke's operations were impacted by a succession of severe storms. Hurricane Florence arrived in mid-September and affected the company's operations in North and South Carolina. One month later, Hurricane Michael came ashore in the gulf region and caused damage all the way from Florida through North and South Carolina. In December 2018, Winter Storm Diego was the third major storm to impact Duke Energy Progress and Duke Energy Carolinas service territories.

Total costs for the three storms was in excess of $1 billion, primarily in Duke Energy Progress' North Carolina and Duke Energy Florida's service territories. Utilities in these territories have a good history of storm recovery, albeit with some regulatory lag. Duke has been working with lawmakers to enact securitization legislation, which would assure recovery of costs at lower cost to customers; however recovery would likely not begin until 2020 and will be spread out over a number of years. In the meantime, Duke's consolidated debt balances are about $1 billion higher than previously forecast, which continues to add negative pressure to credit metrics.

### Recovery of coal ash expenditures primarily resolved, but lag persists and uncertainty is increasing

In 2014, North Carolina lawmakers overwhelmingly passed the Coal Ash Management Act which regulates and requires the closure of coal ash basins at all coal plant sites throughout the state. The legislation, which was amended in 2016, required Duke to take costly, immediate action to excavate and close coal ash basins at three of its highest risk sites by the end of 2019. These basins were all successfully closed ahead of schedule by July 2019. A fourth basin is required to be closed by August 2022. The 2016 amendment required the remaining sites to be closed by either 2024 or 2029, depending on their priority designation.

In April 2019, the North Carolina Department of Environmental Quality (NCDEQ) ordered Duke Energy to excavate coal ash at all of its low-risk sites in North Carolina where specific closure plans had not been determined. The decision is credit negative as it will cost substantially more than the alternative closure options proposed by Duke for these six sites, and in some cases it may take decades, stretching well beyond current state and federal deadlines. The company is required to submit closure plans by December 31, 2019. Duke has appealed the order to the North Carolina Office of Administrative Hearings. In August 2019 the court issued an order dismissing several of Duke's claims relating to procedure, but allowing the substantive claims to move forward. The company expects the process will take 9-12 months.

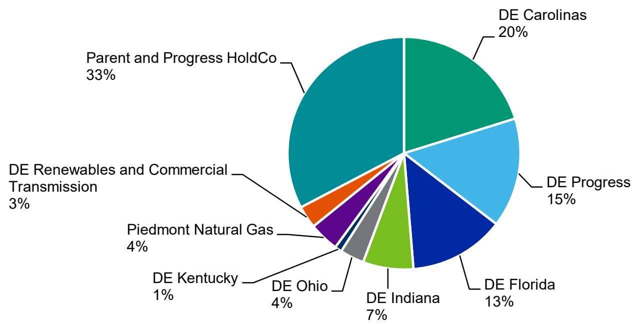
In 2014, Duke recognized a $3.5 billion Asset Retirement Obligation (ARO) for its estimated obligations to close its North Carolina coal ash basins. In the second quarter of 2015, after publication of the EPA's final Coal Combustion Rules, Duke incrementally increased the ARO by $1 billion as it created additional obligations for the company in South Carolina, Indiana, and Kentucky, putting its total ARO at $4.5 billion. Duke continues to refine its estimated obligations as work continues on the sites and there is additional information around closure requirements. As of June 30, 2019, Duke had spent approximately $2.1 billion and its total ARO had increased to approximately $6.5 billion ($2 billion more than reported as of December 2018).

In Duke's largest jurisdictions in North and South Carolina, coal ash basin closure and remediation spending is not recovered via trackers or other automatic cost recovery provisions and must be recovered via base rate case filings. As a result, there will likely continue to be regulatory lag in the recovery of these costs. To date, the majority of coal ash expenditures incurred have been recovered with rate base like treatment. Therefore we currently view the spending for coal ash remediation to be akin to a capital expenditure. However in their most recent South Carolina rate cases Duke Energy Progress and Duke Energy Carolinas were denied recovery of certain coal ash costs. The company plans to appeal this decision and we note that it represents a relatively modest portion of total incurred costs. Depending on the outcome of the appeal, we may modify our treatment of the portion of expenditures that are not recoverable.

### Equity issuance has contained parent leverage – but it will still be relatively high

Duke's $2 billion 2018 equity issuance, and its plans for ongoing issuance of $500 million per year, have helped control the company's need for parent level debt financing. Prior to the announced 2018 equity issuance, we expected the level of parent debt to spike in 2018 and 2019 due in part to investments in ACP. Currently, we expect the proportion of Duke parent debt as a percentage of total consolidated debt will remain under 35%. This is still relatively high when compared to some other regulated utility holding company peers, and a factor in the wide differential between Duke and most of its subsidiaries' credit quality.

Exhibit 6
**2018 Reported Debt by Entity**

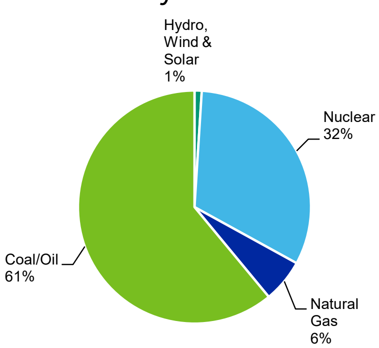



*Source: Moody's Investors Service, Company*

## Environmental, social and governance considerations

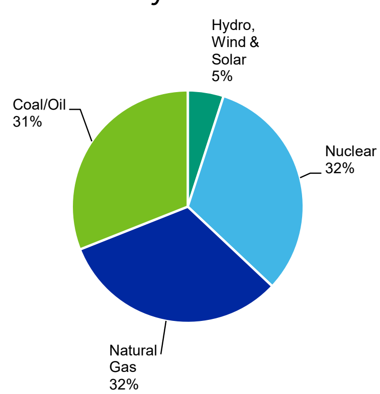
Duke has moderate carbon transition risk within the regulated utility sector as the majority of its energy is generated by fossil fuels. Since 2005, Duke has reduced carbon dioxide emissions by 31% and currently plans a 50% (increased from 40% in 2017) reduction by 2030. Furthermore Duke just announced a goal to achieve net-zero carbon emissions by 2050. As of 2018, the company's consolidated net output included about 31% from coal / oil fired resources, versus about 61% in 2005. By 2030 Duke estimates that 15% of its total company generation will be fired by coal.

Exhibit 7
**2005 Fuel Diversity**



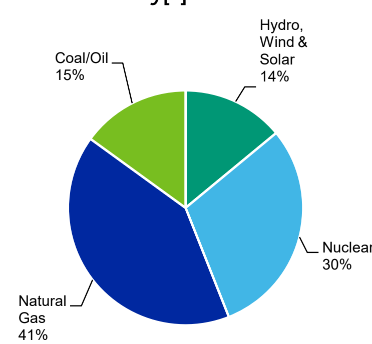

*Source: Company*

Exhibit 8
**2018 Fuel Diversity**




*Source: Company*

Exhibit 9
**2030 Fuel Diversity[1]**




[1] Company Estimate
*Source: Company*

## Liquidity analysis

Given its large capital programs, Duke is reliant on external sources of liquidity. For the twelve months ending June 2019, Duke's consolidated cash flow from operations was approximately $7 billion while cash used for investing activities was about $10.5 billion and the company paid around $2.6 billion in dividends resulting in negative free cash flow of approximately $6 billion. The shortfall was funded via a combination of sources including subsidiary and parent level debt as well as preferred and common equity (about $2 billion).

As of June 2019, the Duke had $336 million of cash and short-term investments on hand, $3.9 billion available under its $8 billion master credit facility, and $500 million available under its $1 billion parent level revolving credit facility (May 2022 expiration). The master credit facility matures in March 2024 and includes sub-limits for each of its utility subsidiaries. As of June 30, 2019, Duke's parent company borrowing sub-limit under the master credit facility was $2.65 billion, and the subsidiary sub-limits were: $1.25 billion for Duke Energy Progress, $800 million for Duke Energy Florida, $1.75 billion for Duke Energy Carolinas, $600 million for Duke Energy Indiana, $450 million for Duke Energy Ohio, and $500 million for Piedmont Natural Gas.

The master credit facility supports a $4.85 billion commercial paper program. The facility does not contain a material adverse change clause for new borrowings and has a single financial covenant requiring that Duke and its utility subsidiaries each maintain a consolidated debt to capitalization ratio of no more than 65%, except for Piedmont. The debt to capital covenant for Piedmont is a maximum of 70%. As of June 30, 2019, we estimate Duke's consolidated ratio to be about 57%.

As of June 30, 2019, Duke had about $3.4 billion of commercial paper outstanding, including about $1 billion allocated to the parent company under its $2.65 billion credit facility sub-limit. Of the total $8 billion master credit facility, Duke and its utilities had about $3.9 billion of availability with $3.4 billion of commercial paper, $500 million of coal ash set-aside, $81 million of tax-exempt bonds, and $53 million of letters of credit outstanding. Duke also maintains a money pool arrangement among its utility subsidiaries allowing it to more efficiently utilize available cash balances throughout the organization.

As an additional source of liquidity Duke also has the ability to raise short-term debt through a variable rate demand note program called PremierNotes. The company's filings with the SEC indicate that no more than $1.5 billion of such notes will be outstanding. The notes have no stated maturity date and can be redeemed in whole or in part by Duke or at the investor's option at any time. As of June 30, 2019, Duke had about $991 million of PremierNotes outstanding. Although not explicitly backed by Duke's bank credit facility, the facility could be used to fund the maturities of such notes. These notes are classified as part of the $3.8 billion total notes payable and commercial paper outstanding as of June 30, 2019.

Duke's scheduled long-term debt maturities over the twelve months beginning June 30, 2019 total approximately $2.35 billion, including approximately $830 million at the parent level Duke Corp., $350 million at Progress Energy, $450 million at Duke Carolinas, $600 million at Duke Florida, $100 million at Duke Kentucky. We expect most of this debt will be refinanced.

## Rating methodology and scorecard factors

Exhibit 10
Rating Factors
Duke Energy Corporation

| Regulated Electric and Gas Utilities Industry Scorecard [1][2] | Current LTM 6/30/2019 | | Moody's 12-18 Month Forward View As of Date Published [3] | |
|---|---|---|---|---|
| **Factor 1 : Regulatory Framework (25%)** | **Measure** | **Score** | **Measure** | **Score** |
| a) Legislative and Judicial Underpinnings of the Regulatory Framework | A | A | A | A |
| b) Consistency and Predictability of Regulation | Aa | Aa | Aa | Aa |
| **Factor 2 : Ability to Recover Costs and Earn Returns (25%)** | | | | |
| a) Timeliness of Recovery of Operating and Capital Costs | A | A | A | A |
| b) Sufficiency of Rates and Returns | Baa | Baa | Baa | Baa |
| **Factor 3 : Diversification (10%)** | | | | |
| a) Market Position | Aa | Aa | Aa | Aa |
| b) Generation and Fuel Diversity | A | A | A | A |
| **Factor 4 : Financial Strength (40%) [4]** | | | | |
| a) CFO pre-WC + Interest / Interest (3 Year Avg) | 4.6x | A | 4.6x - 5x | A |
| b) CFO pre-WC / Debt (3 Year Avg) | 14.3% | Baa | 14% - 16% | Baa |
| c) CFO pre-WC – Dividends / Debt (3 Year Avg) | 10.0% | Baa | 10% - 12% | Baa |
| d) Debt / Capitalization (3 Year Avg) | 51.8% | Baa | 50% - 54% | Baa |
| **Rating:** | | | | |
| Scorecard-Indicated Outcome Before Notching Adjustment | | A3 | | A3 |
| HoldCo Structural Subordination Notching | -1 | -1 | -1 | -1 |
| a) Scorecard-Indicated Outcome | | Baa1 | | Baa1 |
| b) Actual Rating Assigned | | Baa1 | | Baa1 |

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 6/30/2019(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
[4] Standard risk grid for financial strength
*Source: Moody's Financial Metrics*

# Appendix

Exhibit 11

## Cash Flow and Credit Metrics [1]

| CF Metrics | Dec-15 | Dec-16 | Dec-17 | Dec-18 | LTM Jun-19 |
|---|---|---|---|---|---|
| As Adjusted | | | | | |
| **FFO** | 7,638 | 7,586 | 8,514 | 8,954 | 9,540 |
| +/- Other | (459) | (323) | (496) | (1,047) | (931) |
| **CFO Pre-WC** | 7,179 | 7,263 | 8,018 | 7,907 | 8,609 |
| +/- ΔWC | 181 | 394 | (752) | (138) | (993) |
| **CFO** | 7,360 | 7,657 | 7,266 | 7,769 | 7,616 |
| - Div | 2,269 | 2,338 | 2,457 | 2,484 | 2,587 |
| - Capex | 7,278 | 8,697 | 8,687 | 9,959 | 11,209 |
| **FCF** | (2,187) | (3,378) | (3,878) | (4,674) | (6,179) |
| | | | | | |
| (CFO Pre-W/C) / Debt | 17.3% | 14.6% | 14.8% | 13.7% | 14.0% |
| (CFO Pre-W/C - Dividends) / Debt | 11.8% | 9.9% | 10.3% | 9.4% | 9.8% |
| FFO / Debt | 18.4% | 15.2% | 15.7% | 15.5% | 15.5% |
| RCF / Debt | 12.9% | 10.5% | 11.2% | 11.2% | 11.3% |
| Debt / EBITDA | 4.4x | 5.1x | 5.0x | 5.5x | 5.6x |
| | | | | | |
| Revenue | 22,371 | 22,743 | 23,565 | 24,521 | 24,779 |
| Cost of Good Sold | 7,338 | 6,789 | 6,863 | 7,396 | 7,390 |
| EBITDA | 9,417 | 9,728 | 10,737 | 10,480 | 10,927 |
| Interest Expense | 1,681 | 1,977 | 2,171 | 2,330 | 2,388 |
| Net Income | 2,530 | 2,119 | 3,106 | 2,281 | 2,627 |
| Total Assets | 119,812 | 131,655 | 136,911 | 144,659 | 151,314 |
| Total Liabilities | 80,026 | 90,739 | 95,410 | 101,027 | 106,786 |
| Total Equity | 39,785 | 40,916 | 41,501 | 43,633 | 44,529 |

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
*Source: Moody's Financial Metrics*

Exhibit 12

## Peer Comparison Table [1]

| | Duke Energy Corporation | | | American Electric Power Company, Inc. | | | Southern Company (The) | | | Xcel Energy Inc. | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Baa1 Stable | | | Baa1 Stable | | | Baa2 Stable | | | Baa1 Stable | | |
| | FYE | FYE | LTM | FYE | FYE | LTM | FYE | FYE | LTM | FYE | FYE | LTM |
| (in US millions) | Dec-17 | Dec-18 | Jun-19 | Dec-17 | Dec-18 | Jun-19 | Dec-17 | Dec-18 | Jun-19 | Dec-17 | Dec-18 | Jun-19 |
| Revenue | 23,565 | 24,521 | 24,779 | 15,425 | 16,196 | 15,765 | 23,031 | 23,495 | 22,006 | 11,404 | 11,537 | 11,646 |
| CFO Pre-W/C | 8,018 | 7,907 | 8,609 | 4,580 | 4,831 | 4,572 | 7,242 | 7,107 | 6,245 | 3,314 | 3,116 | 3,083 |
| Total Debt | 54,169 | 57,787 | 61,455 | 24,138 | 26,588 | 28,552 | 51,414 | 47,808 | 46,185 | 16,917 | 18,376 | 19,243 |
| CFO Pre-W/C / Debt | 14.8% | 13.7% | 14.0% | 19.0% | 18.2% | 16.0% | 14.1% | 14.9% | 13.5% | 19.6% | 17.0% | 16.0% |
| CFO Pre-W/C – Dividends / Debt | 10.3% | 9.4% | 9.8% | 14.0% | 13.4% | 11.4% | 9.4% | 9.7% | 5.3% | 15.3% | 13.0% | 12.1% |
| Debt / Capitalization | 53.0% | 52.9% | 53.6% | 49.2% | 50.6% | 51.6% | 60.2% | 56.2% | 53.3% | 52.8% | 53.2% | 53.9% |

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
*Source: Moody's Financial Metrics*

I/A

## Ratings

Exhibit 13

| Category | Moody's Rating |
|---|---|
| **DUKE ENERGY CORPORATION** | |
| Outlook | Stable |
| Issuer Rating | Baa1 |
| Sr Unsec Bank Credit Facility | Baa1 |
| Senior Unsecured | Baa1 |
| Jr Subordinate | Baa2 |
| Pref. Stock | Baa3 |
| Commercial Paper | P-2 |
| **DUKE ENERGY CAROLINAS, LLC** | |
| Outlook | Stable |
| Issuer Rating | A1 |
| First Mortgage Bonds | Aa2 |
| Bkd Senior Secured | Aa2 |
| Senior Unsecured | A1 |
| **DUKE ENERGY PROGRESS, LLC** | |
| Outlook | Stable |
| Issuer Rating | A2 |
| First Mortgage Bonds | Aa3 |
| Senior Secured | Aa3 |
| **DUKE ENERGY INDIANA, LLC.** | |
| Outlook | Stable |
| Issuer Rating | A2 |
| First Mortgage Bonds | Aa3 |
| Senior Secured | Aa3 |
| Senior Unsecured | A2 |
| **PROGRESS ENERGY, INC.** | |
| Outlook | Stable |
| Senior Unsecured | Baa1 |
| **PIEDMONT NATURAL GAS COMPANY, INC.** | |
| Outlook | Stable |
| Senior Unsecured | A3 |
| Commercial Paper | P-2 |
| **DUKE ENERGY OHIO, INC.** | |
| Outlook | Stable |
| Issuer Rating | Baa1 |
| First Mortgage Bonds | A2 |
| Senior Unsecured | Baa1 |
| **DUKE ENERGY KENTUCKY, INC.** | |
| Outlook | Stable |
| Senior Unsecured | Baa1 |

*Source: Moody's Investors Service*

REPORT NUMBER 1196333

MOODY'S
INVESTORS SERVICE

# YOUNG REBUTTAL EXHIBIT NO. 4

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
30 March 2020

Update

Rate this Research

RATINGS

**Duke Energy Progress, LLC**

| | |
|---|---|
| Domicile | North Carolina, United States |
| Long Term Rating | A2 |
| Type | LT Issuer Rating |
| Outlook | Stable |

*Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.*

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# Duke Energy Progress, LLC

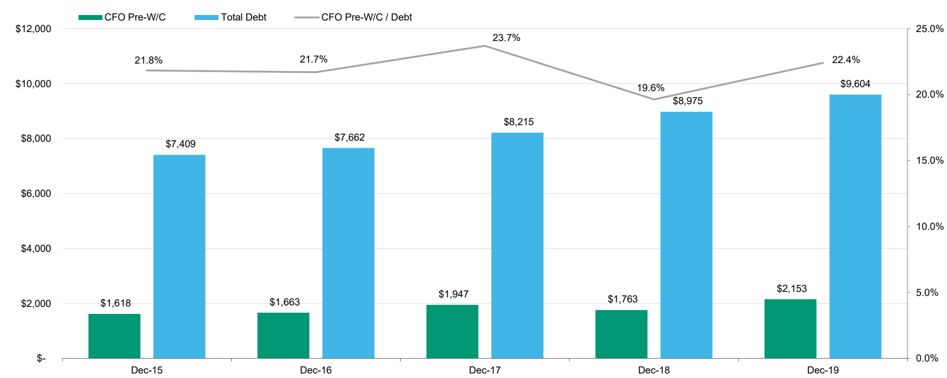
Update to credit analysis

## Summary

Duke Energy Progress, LLC's credit reflects its business and operating risk profile as a fully regulated utility with service territories in historically credit supportive environments in both North and South Carolina, although challenges have recently emerged. The company's 2018 financial metrics were impacted by severe storm activity; in 2019 they rebounded to what we expect are more sustainable levels.

Exhibit 1

**Historical CFO Pre-WC, Total Debt, and CFO Pre-WC to Debt ($MM)**




*Source: Moody's Financial Metrics*

## Credit strengths

» Credit supportive regulatory environments

» Reasonable financial credit metrics

» Position as part of the Duke Energy corporate family

## Credit challenges

» Uncertainty regarding ability to fully recover coal ash remediation spending with a return in all jurisdictions

» Storm prone service territory and uncertain impact of coronavirus

» Capital expenditures for coal ash basin remediation and T&D upgrades will remain substantial

## Rating outlook

The stable rating outlook reflects the utility's relatively low business risk profile, historically credit supportive regulatory frameworks, and our expectation that the company will be able to sustain CFO pre-WC to debt ratios the low 20% range. The outlook assumes Duke Energy Progress' sizeable capital expenditure program will be well managed and that debt levels will be maintained at levels appropriate for the utility's current credit quality. The stable outlook also reflects our expectation that the company will continue to be able to recover the majority of its coal ash closure and remediation costs with a full return, as well as its storm restoration expenditures, in rates. However, regulatory lag and the lingering impacts of federal tax reform may continue to pressure metrics.

## Factors that could lead to an upgrade

» A reduction in leverage, possibly due to lower spending for capital expenditures

» A ratio of CFO pre-WC to debt above 25% on a sustained basis

## Factors that could lead to a downgrade

» A decline in the credit supportiveness of the regulatory environments in North or South Carolina

» A ratio of CFO pre-WC to debt below 20% on a sustained basis

## Key indicators

Exhibit 2
**Duke Energy Progress, LLC [1]**

| | Dec-15 | Dec-16 | Dec-17 | Dec-18 | Dec-19 |
|---|---|---|---|---|---|
| CFO Pre-W/C + Interest / Interest | 6.9x | 6.7x | 6.9x | 5.9x | 7.1x |
| CFO Pre-W/C / Debt | 21.8% | 21.7% | 23.7% | 19.6% | 22.4% |
| CFO Pre-W/C – Dividends / Debt | 21.8% | 17.8% | 22.2% | 17.7% | 22.4% |
| Debt / Capitalization | 42.5% | 41.9% | 45.7% | 46.1% | 45.4% |

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
*Source: Moody's Financial Metrics*

## Profile

Duke Energy Progress, LLC is a vertically integrated electric utility serving approximately 1.6 million customers in North Carolina and South Carolina. Duke Energy Progress is a subsidiary of intermediate holding company Progress Energy, Inc. and parent company Duke Energy Corporation (Duke Energy).

## Detailed credit considerations

### Generally credit supportive regulatory environments

Duke Energy Progress has service territories in both North and South Carolina, two fully regulated states with generally credit supportive regulatory environments. Both states have historically authorized somewhat above average equity layers and returns and have mechanisms in place for the timely recovery of fuel costs. However, a reliance on traditional base rate case proceedings, rather than riders or trackers for the recovery of other increased costs or investment, leaves utilities in both states susceptible to regulatory lag. We are also closely watching the regulatory treatment of coal ash remediation spending.

In North Carolina, the North Carolina Utilities Commission (NCUC) in February 2018 authorized an approximate $193 million (6%) annual increase in base rates (reduced by $43 million for four years to return excess state income tax) incorporating a return on equity (ROE) of 9.9% and a 52% equity ratio. The final order authorized a partial settlement agreement between Duke Energy Progress and the NCUC Public Staff with regard to certain, traditional rate making parameters, including the ROE and equity ratio, and also resolved the outstanding issues of coal ash and storm cost recovery discussed below.

The February 2018 North Carolina order incorporated recovery of the majority of deferred coal ash remediation costs (approximately $234 million) over five years with an ability to earn a return at Duke Energy Progress' weighted average cost of capital (debt and equity). The NCUC also authorized recovery and return for $51 million (out of $80 million requested) of deferred storm costs incurred for Hurricane Matthew (a 2016 storm). We view the ability to reach a settlement agreement on traditional ratemaking parameters, and the approval for the recovery of coal ash and storm costs with a return, as credit positive. We note however that the decision has been appealed by the state Attorney General and the Public Staff, and that the NCUC has recently taken a different position in the case of another smaller utility operating in the state. In the case of Virginia Electric and Power Company (A2 stable), the NCUC authorized recovery of coal ash spending, but over a ten-year period rather than five, with no return during the amortization period.

In October 2019, Duke Energy Progress filed a base rate case in North Carolina requesting an approximate 12% increase in revenue premised on a 53% equity ratio and a 10.3% return on equity. The filing also seeks recovery of $530 million of coal ash remediation costs deferred from September 2017 - February 2020 over five years. The utility requested rates become effective no later than September 2020; however, the procedural schedule will likely be pushed out due to the impact of COVID-19.

In South Carolina, in May 2019 the Public Service Commission of South Carolina (PSCSC) denied recovery of the majority of the Duke Energy Progress' incremental South Carolina allocated spending on coal ash recovery. The company has appealed this decision. On a positive note, the South Carolina order did continue authorization of the utility's ability to earn a full weighted average cost of capital return on the approved portion of its coal ash remediation spending, which included costs incurred through 2016. The order also shortened the recovery period to five years, versus a previously approved fifteen years.

Our stable outlook assumes Duke Energy Progress will continue to be allowed to recover the majority of its coal ash remediation spending, and that it will be able to earn a return on the deferred balance.

### Part of the Duke corporate family

Duke Energy Progress' credit profile reflects its position as part of the Duke corporate family and the largest utility system in the Carolinas, benefitting from fuel purchasing power and joint generation dispatch synergies with affiliate Duke Energy Carolinas.

### Financial metrics are expected to remain supportive of credit quality

After declining due primarily to storm related activity in 2018, Duke Energy Progress' cash flow coverage metrics have begun to show the positive impact of recent rate case activity and the recovery of some prior coal ash remediation spending. Although there will continue to be lag in the recovery of coal ash spending, we expect the company will file frequent rate cases to mitigate this impact. Assuming the continuation of reasonably supportive rate treatment and prudent financial policy, we expect that Duke Energy Progress will maintain a CFO pre-WC to debt ratio at or near the lower end of the range of 22% to 30% indicated for a score of "A" on this factor in our Regulated Electric and Gas Utility rating methodology.

We note however, that the rapid and widening spread of the coronavirus outbreak, and the associated deteriorating global economic outlook, are creating a severe and extensive credit shock across many sectors. While the regulated framework provides a tremendous amount of insulation and support for utilities, a material reduction in customer demand can lower revenues, affect the timeliness of cost recovery and constrain utility cash flow until the next rate case and/or rate adjustment. Longer term, recessionary pressures may increase regulatory resistance to rate increases, which could also negatively impact credit metrics.

### Capital expenditures are expected to moderate somewhat in the near-term, but remain substantial

Over the 2015-2017 period, Duke Energy Progress' annual capital expenditures (inclusive of coal ash remediation spending) were about $1.9 billion per year. In 2018 and 2019, annual spending inclusive of coal ash remediation increased to about $2.5 billion. While spending is expected to moderate somewhat in 2020 and 2021, it will remain robust, at around $2.1 billion and before increasing in the latter part of the company's five-year plan. Most of the investment can be attributed to new generation requirements, transmission and distribution system upgrades, and coal ash basin remediation costs.

Payments for coal ash related asset retirement obligations have risen from zero in 2014, to $109 million in 2015, about $200 – 230 million per year in 2016 – 2018, and $390 million in 2019. In 2020, we anticipate environmental spending, inclusive of coal ash remediation, will be about $450 million before subsiding to an annual rate of about $200 million in 2021 and beyond. The decline is reflective the completion of work at "high-risk" ash remediation sites in 2019, and a settlement reached with the North Carolina

Department of Environmental Quality (NCDEQ) that allows the majority of the remaining expenditures to occur over a period of 15-20 years.

### Continued regulatory lag and uncertainty regarding the recovery of coal ash spending could maintain some negative pressure on coverage metrics

In 2014, Duke recognized a $3.5 billion Asset Retirement Obligation (ARO) for its estimated obligations to close its North Carolina coal ash basins, including approximately $1.8 billion at Duke Energy Progress. In the second quarter of 2015, after publication of the EPA's final Coal Combustion Rules, Duke incrementally increased the ARO by $1 billion as it created additional obligations for the company in South Carolina, Indiana, and Kentucky, putting its total ARO at $4.5 billion. In December of 2019, Duke reached an agreement with the NCDEQ establishing the means and timeframes for remediation of its remaining coal ash basins, which included full excavation of the majority of the ash over a period of 15-20 years. As of December 31, 2019, Duke had spent approximately $2.5 billion, including $1 billion at Duke Energy Progress, and its total ARO was estimated at $6.3 billion, including $2.4 billion at Duke Energy Progress.

Duke Energy Progress' coal ash basin closure and remediation spending is not recovered via trackers or other automatic cost recovery provisions and must be recovered via base rate case filings. As result, there will likely continue to be regulatory lag in the recovery of these costs, and there is an increased risk that recovery of, or a return on, the spending may be denied.

Currently, as a result of the rate base like treatment of the majority of Duke Energy Progress' spending for coal ash remediation, we view these costs as being akin to a capital expenditure. Depending on the outcome of its pending North Carolina rate case, and South Carolina coal-ash related appeals, we may modify our treatment of the portion of expenditures that are not recoverable, or for which a return is not authorized.

### ESG considerations

Environmental considerations incorporated into our credit analysis for Duke Energy Progress are primarily related to carbon regulations. Duke Energy Progress has a moderate carbon transition risk within the regulated utility sector because as an integrated utility its generation ownership places it at a higher risk profile than transmission and distribution companies. As of December 31, 2019, approximately 27% of Duke Energy Progress' 12,994 MW generation portfolio is coal fired. In 2019, energy from Duke Energy Progress' owned capacity was generated 47% from nuclear fuel, which lowers the company's carbon footprint, 35% from oil and natural gas, and 16% from coal. Social risks are primarily related to health and safety as well as demographic and societal trends. Corporate governance considerations include financial policy and we note that a strong financial position is an important characteristic for managing environmental and social risks.

## Liquidity analysis

Duke Energy Progress maintains an adequate liquidity profile. For the year ended December 31, 2019, Duke Energy Progress generated approximately $2.2 billion of cash from operations (CFO), invested approximately $2.5 billion in capital expenditures (including coal ash remediation spending) and made no distributions, resulting in negative free cash flow (FCF) of approximately $290 million. In 2018, Duke Progress generated approximately $1.9 billion of CFO, invested approximately $2.4 billion in capital expenditures and distributed $175 million in dividend payments, resulting in negative FCF of approximately $767 million. Going forward, we expect Duke Energy Progress to remain cash flow negative and that shortfalls will continue to be funded via a combination of internal and external sources.

Duke Energy Progress' additional liquidity sources include its access to funding from the Duke parent company's commercial paper program through the Duke system money pool, and from direct borrowings from the money pool. As of December 31, 2019, the utility also has $1.25 billion of direct borrowing capacity under Duke Energy's master five-year credit facility, of which $791 million was available. Under a 2015 plea agreement with the U.S. Department of Justice, Duke Energy Progress is required to maintain $250 million of available capacity under the master credit facility related to violations at North Carolina facilities with coal ash basins. In March 2020, Duke extended its $8.0 billion master credit facility by one year to March 2025. Duke Energy's master credit facility does not contain a material adverse change clause for new borrowings. The facility contains a single financial covenant requiring Duke Energy and its utility subsidiaries to maintain a consolidated debt to capitalization ratio of no more that 65%, except for Piedmont Natural Gas Company (Piedmont). The debt to capital covenant level for Piedmont is 70%. As of December 31, 2019, each company was reported to be in compliance with this covenant and we estimate Duke Energy Progress' ratio to be about 50%.

Duke Energy Progress' nearest long-term debt maturities are $300 million of first mortgage bonds due in September 2020 and a $700 million term loan due in December 2020.

## Rating methodology and scorecard factors

Exhibit 3
**Rating Factors**
**Duke Energy Progress, LLC**

| Regulated Electric and Gas Utilities Industry Scorecard [1][2] | Current FY 12/31/2019 | | Moody's 12-18 Month Forward View As of Date Published [3] | |
|---|---|---|---|---|
| **Factor 1 : Regulatory Framework (25%)** | **Measure** | **Score** | **Measure** | **Score** |
| a) Legislative and Judicial Underpinnings of the Regulatory Framework | A | A | A | A |
| b) Consistency and Predictability of Regulation | Aa | Aa | Aa | Aa |
| **Factor 2 : Ability to Recover Costs and Earn Returns (25%)** | | | | |
| a) Timeliness of Recovery of Operating and Capital Costs | A | A | A | A |
| b) Sufficiency of Rates and Returns | Baa | Baa | Baa | Baa |
| **Factor 3 : Diversification (10%)** | | | | |
| a) Market Position | Baa | Baa | Baa | Baa |
| b) Generation and Fuel Diversity | A | A | A | A |
| **Factor 4 : Financial Strength (40%)** | | | | |
| a) CFO pre-WC + Interest / Interest (3 Year Avg) | 6.6x | Aa | 6.6x - 7x | Aa |
| b) CFO pre-WC / Debt (3 Year Avg) | 21.9% | Baa | 21% - 23% | A |
| c) CFO pre-WC – Dividends / Debt (3 Year Avg) | 20.8% | A | 16% - 20% | A |
| d) Debt / Capitalization (3 Year Avg) | 45.7% | Baa | 42% - 46% | A |
| **Rating:** | | | | |
| Scorecard-Indicated Outcome Before Notching Adjustment | | A2 | | A2 |
| HoldCo Structural Subordination Notching | 0 | 0 | 0 | 0 |
| a) Scorecard-Indicated Outcome | | A2 | | A2 |
| b) Actual Rating Assigned | | A2 | | A2 |

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 12/31/2019
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
*Source: Moody's Financial Metrics*

## Appendix

Exhibit 4

### Cash Flow and Credit Metrics [1]

| CF Metrics | Dec-15 | Dec-16 | Dec-17 | Dec-18 | Dec-19 |
|---|---|---|---|---|---|
| As Adjusted | | | | | |
| **FFO** | **1,767** | **1,814** | **2,018** | **2,198** | **2,322** |
| +/- Other | (149) | (151) | (71) | (435) | (169) |
| **CFO Pre-WC** | **1,618** | **1,663** | **1,947** | **1,763** | **2,153** |
| +/- ΔWC | 216 | 516 | (524) | 93 | 86 |
| **CFO** | **1,834** | **2,179** | **1,423** | **1,856** | **2,239** |
| - Div | - | 300 | 124 | 175 | - |
| - Capex | 1,887 | 1,977 | 1,943 | 2,448 | 2,529 |
| **FCF** | **(53)** | **(98)** | **(644)** | **(767)** | **(290)** |
| | | | | | |
| (CFO Pre-W/C) / Debt | 21.8% | 21.7% | 23.7% | 19.6% | 22.4% |
| (CFO Pre-W/C - Dividends) / Debt | 21.8% | 17.8% | 22.2% | 17.7% | 22.4% |
| FFO / Debt | 23.9% | 23.7% | 24.6% | 24.5% | 24.2% |
| RCF / Debt | 23.9% | 19.8% | 23.1% | 22.5% | 24.2% |
| | | | | | |
| Revenue | 5,290 | 5,277 | 5,129 | 5,699 | 5,957 |
| Cost of Good Sold | 1,944 | 1,799 | 1,571 | 1,853 | 1,974 |
| Interest Expense | 276 | 294 | 333 | 362 | 350 |
| Net Income | 517 | 580 | 702 | 570 | 768 |
| Total Assets | 25,470 | 26,876 | 28,305 | 30,376 | 33,349 |
| Total Liabilities | 18,477 | 19,583 | 20,427 | 22,011 | 24,183 |
| Total Equity | 6,993 | 7,293 | 7,878 | 8,365 | 9,166 |

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
*Source: Moody's Financial Metrics*

Exhibit 5

### Peer Comparison Table [1]

| | Duke Energy Progress, LLC (P)A2 Stable | | | Dominion Energy South Carolina, Inc. Baa2 Stable | | | Duke Energy Carolinas, LLC A1 Stable | | | Georgia Power Company Baa1 Stable | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | FYE | FYE | FYE | FYE | FYE | LTM | FYE | FYE | LTM | FYE | FYE | LTM |
| (in US millions) | Dec-17 | Dec-18 | Dec-19 | Dec-17 | Dec-18 | Dec-19 | Dec-17 | Dec-18 | Dec-19 | Dec-17 | Dec-18 | Dec-19 |
| Revenue | 5,129 | 5,699 | 5,957 | 3,070 | 2,762 | 1,929 | 7,302 | 7,300 | 7,395 | 8,310 | 8,420 | 8,408 |
| CFO Pre-W/C | 1,947 | 1,763 | 2,153 | 1,228 | 653 | 647 | 2,844 | 2,862 | 3,143 | 2,474 | 2,549 | 2,852 |
| Total Debt | 8,215 | 8,975 | 9,604 | 5,524 | 5,360 | 4,237 | 10,463 | 11,665 | 12,151 | 12,267 | 10,586 | 13,708 |
| CFO Pre-W/C / Debt | 23.7% | 19.6% | 22.4% | 22.2% | 12.2% | 15.3% | 27.2% | 24.5% | 25.9% | 20.2% | 24.1% | 20.8% |
| CFO Pre-W/C – Dividends / Debt | 22.2% | 17.7% | 22.4% | 16.5% | 9.0% | 14.6% | 21.2% | 18.1% | 23.6% | 9.7% | 10.9% | 9.3% |
| Debt / Capitalization | 45.7% | 46.1% | 45.4% | 47.4% | 50.3% | 48.6% | 41.6% | 43.3% | 42.2% | 44.7% | 37.8% | 42.8% |

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
*Source: Moody's Financial Metrics*

## Ratings

Exhibit 6

| Category | Moody's Rating |
|---|---|
| **DUKE ENERGY PROGRESS, LLC** | |
| Outlook | Stable |
| Issuer Rating | A2 |
| First Mortgage Bonds | Aa3 |
| Senior Secured | Aa3 |
| Senior Unsecured Shelf | (P)A2 |
| **ULT PARENT: DUKE ENERGY CORPORATION** | |
| Outlook | Stable |
| Issuer Rating | Baa1 |
| Sr Unsec Bank Credit Facility | Baa1 |
| Senior Unsecured | Baa1 |
| Jr Subordinate | Baa2 |
| Pref. Stock | Baa3 |
| Commercial Paper | P-2 |
| **PARENT: PROGRESS ENERGY, INC.** | |
| Outlook | Stable |
| Senior Unsecured | Baa1 |

*Source: Moody's Investors Service*

REPORT NUMBER 1217309

MOODY'S
INVESTORS SERVICE

# YOUNG REBUTTAL EXHIBIT NO. 5

BofA GLOBAL RESEARCH

BofA SECURITIES

# Duke Energy

# Rolling into 2020 with a potential positive guide while lingering LT risks remain clear

**Reiterate Rating: UNDERPERFORM | PO: 96.00 USD | Price: 90.44 USD**

## ’20 guide could be positive yet still risks in NC/renewables

With DUK trading at a substantial discount (-15%) and appearing optically cheap compared to peers, we remain cautious on the overall outlook. While 2020 guidance could prove to be somewhat better than initially expected (we now move our est. to $5.18 and provide our EPS walk further below) with incremental capital expected to added to the long-term outlook, we continue to see ongoing risks to the most critical piece to the story in NC with three untested commissioners and uncertainty related to coal ash recovery. While nominally addressed in the last case and pending still before the Supreme Court, ability to navigate a successful outcome and maintain a return on/of capital (WACC) rather than a more punitive approach or write-down of assets remains uncertain (we provide our assumptions for total EPS at risk below as well). More near-term risks include the renewable earnings outlook and associated spending levels where a sizeable increase would be perceived cautiously unless mgmt. can clearly articulate it is incremental rather than filling a regulated earnings gap. Further, while we believe the company will receive support for its Edwardsport plant to be placed in rates, we see a settlement as unlikely and could see a drop in authorized returns. Bottom line, we continue to see revision risk into 4Q results & thru ’20; we reiterate our Underperform despite the latest drop in shares.

## Reiterate Underperform as risk/reward not yet balanced

We modestly increase our EPS assumptions through the outlook period but we remain at the low-end of mgmt. 4-6% guided growth trajectory. We provide our earnings walk for both 4Q19 ($0.90) and 2020 EPS with an expect range of $5.10-5.30, which would be *positive* compared to street assumptions for current year. Still we remain cautious on the longer-term outlook with several hurdles ahead in NC, not to mention expected minimal updates on ACP until Feb 24 for the Supreme Court case and 1H20 for the Biological Opinion. We move our PO to $96 (from $95) on our latest estimates and mark-to-market of peer utility multiples of 18.8x for electric (from 18.7x) and 18.8x for gas (from 18.3x). Resolution in NC, remains the most critical piece with risk/reward prospects still not balanced despite upside in our SOTP analysis.

**Estimates (Dec)**

| (US$) | 2017A | 2018A | 2019E | 2020E | 2021E |
|---|---|---|---|---|---|
| EPS | 4.57 | 4.72 | 5.05 | 5.18 | 5.42 |
| GAAP EPS | 4.37 | 4.69 | 5.11 | 5.26 | 5.49 |
| EPS Change (YoY) | -2.6% | 3.3% | 7.0% | 2.6% | 4.6% |
| Consensus EPS (Bloomberg) | | | 5.01 | 5.14 | 5.38 |
| DPS | 3.49 | 3.64 | 3.78 | 3.84 | 3.84 |

**Valuation (Dec)**

| | 2017A | 2018A | 2019E | 2020E | 2021E |
|---|---|---|---|---|---|
| P/E | 19.8x | 19.2x | 17.9x | 17.5x | 16.7x |
| GAAP P/E | 20.7x | 19.3x | 17.7x | 17.2x | 16.5x |
| Dividend Yield | 3.9% | 4.0% | 4.2% | 4.2% | 4.2% |
| EV / EBITDA* | 16.5x | 17.3x | 14.8x | 13.9x | 13.0x |
| Free Cash Flow Yield* | -2.2% | -3.3% | -3.5% | -2.2% | -0.3% |

* For full definitions of *iQmethod* SM measures, see page 12.

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**Refer to important disclosures on page 13 to 15. Analyst Certification on page 10. Price Objective Basis/Risk on page 10.** 12082561

Timestamp: 13 January 2020 07:09AM EST

**13 January 2020**

Equity

### Key Changes

| (US$) | Previous | Current |
|---|---|---|
| Price Obj. | 95.00 | 96.00 |
| 2019E Rev (m) | 25,926.5 | 25,937.9 |
| 2020E Rev (m) | 26,799.2 | 26,844.8 |
| 2021E Rev (m) | 27,786.0 | 27,862.3 |
| 2019E EPS | 5.00 | 5.05 |
| 2020E EPS | 5.13 | 5.18 |
| 2021E EPS | 5.36 | 5.42 |

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### Stock Data

| | |
|---|---|
| Price | 90.44 USD |
| Price Objective | 96.00 USD |
| Date Established | 13-Jan-2020 |
| Investment Opinion | A-3-7 |
| 52-Week Range | 82.46 USD - 97.37 USD |
| Mrkt Val (mn) / Shares Out (mn) | 65,934 USD / 729.0 |
| Average Daily Value (mn) | 318.80 USD |
| BofA Ticker / Exchange | DUK / NYS |
| Bloomberg / Reuters | DUK US / DUK.N |
| ROE (2019E) | 8.1% |
| Net Dbt to Eqty (Dec-2018A) | 130.8% |

ACP – Atlantic Coast Pipeline

# *iQprofile*[SM] Duke Energy

| *iQmethod* [SM] – Bus Performance* | | | | | |
|---|---|---|---|---|---|
| (US$ Millions) | 2017A | 2018A | 2019E | 2020E | 2021E |
| Return on Capital Employed | 3.5% | 3.3% | 4.0% | 4.0% | 4.1% |
| Return on Equity | 7.4% | 6.2% | 8.1% | 7.8% | 7.9% |
| Operating Margin | 24.5% | 19.1% | 22.4% | 22.9% | 23.6% |
| Free Cash Flow | (1,418) | (2,203) | (2,279) | (1,465) | (202) |

| *iQmethod* [SM] – Quality of Earnings* | | | | | |
|---|---|---|---|---|---|
| (US$ Millions) | 2017A | 2018A | 2019E | 2020E | 2021E |
| Cash Realization Ratio | 2.2x | 2.7x | 2.5x | 2.5x | 2.3x |
| Asset Replacement Ratio | 2.0x | 2.0x | 2.5x | 2.3x | 1.9x |
| Tax Rate | 28.0% | 14.6% | 13.0% | 13.0% | 13.0% |
| Net Debt-to-Equity Ratio | 129.6% | 130.8% | 130.8% | 119.9% | 119.4% |
| Interest Cover | 3.1x | 2.5x | 3.0x | 3.0x | 3.1x |

| Income Statement Data (Dec) | | | | | |
|---|---|---|---|---|---|
| (US$ Millions) | 2017A | 2018A | 2019E | 2020E | 2021E |
| Sales | 23,565 | 24,521 | 25,938 | 26,845 | 27,862 |
| % Change | 3.6% | 4.1% | 5.8% | 3.5% | 3.8% |
| Gross Profit | 10,823 | 10,441 | 11,617 | 12,309 | 13,079 |
| % Change | 10.5% | -3.5% | 11.3% | 6.0% | 6.3% |
| EBITDA | 9,280 | 8,848 | 10,330 | 11,005 | 11,759 |
| % Change | 7.8% | -4.7% | 16.8% | 6.5% | 6.8% |
| Net Interest & Other Income | (1,986) | (2,094) | (2,116) | (2,237) | (2,283) |
| Net Income (Adjusted) | 3,059 | 2,666 | 3,674 | 3,834 | 4,156 |
| % Change | 42.1% | -12.8% | 37.8% | 4.4% | 8.4% |

| Free Cash Flow Data (Dec) | | | | | |
|---|---|---|---|---|---|
| (US$ Millions) | 2017A | 2018A | 2019E | 2020E | 2021E |
| Net Income from Cont Operations (GAAP) | 3,065 | 2,647 | 3,716 | 3,894 | 4,216 |
| Depreciation & Amortization | 4,046 | 4,696 | 4,526 | 4,864 | 5,171 |
| Change in Working Capital | 0 | 0 | (111) | (76) | (84) |
| Deferred Taxation Charge | 1,433 | 1,079 | 1,260 | 1,100 | 1,000 |
| Other Adjustments, Net | (1,910) | (1,236) | (206) | (301) | (614) |
| Capital Expenditure | (8,052) | (9,389) | (11,463) | (10,946) | (9,890) |
| Free Cash Flow | -1,418 | -2,203 | -2,279 | -1,465 | -202 |
| % Change | -28.6% | -55.4% | -3.4% | 35.7% | 86.2% |

| Balance Sheet Data (Dec) | | | | | |
|---|---|---|---|---|---|
| (US$ Millions) | 2017A | 2018A | 2019E | 2020E | 2021E |
| Cash & Equivalents | 358 | 591 | 590 | 675 | 760 |
| Trade Receivables | 2,774 | 3,134 | 3,260 | 3,340 | 3,430 |
| Other Current Assets | 5,321 | 5,989 | 6,099 | 6,134 | 6,184 |
| Property, Plant & Equipment | 86,391 | 91,694 | 98,303 | 104,386 | 109,105 |
| Other Non-Current Assets | 43,070 | 43,984 | 43,984 | 43,984 | 43,984 |
| Total Assets | 137,914 | 145,392 | 152,236 | 158,519 | 163,463 |
| Short-Term Debt | 5,407 | 6,816 | 7,206 | 7,356 | 7,696 |
| Other Current Liabilities | 7,075 | 8,225 | 8,350 | 8,389 | 8,445 |
| Long-Term Debt | 49,035 | 51,123 | 54,071 | 55,195 | 57,746 |
| Other Non-Current Liabilities | 34,660 | 35,394 | 35,230 | 34,988 | 34,434 |
| Total Liabilities | 96,177 | 101,558 | 104,857 | 105,929 | 108,321 |
| Total Equity | 41,737 | 43,834 | 46,406 | 51,616 | 54,168 |
| Total Equity & Liabilities | 137,914 | 145,392 | 151,262 | 157,545 | 162,489 |

* For full definitions of *iQmethod*[SM] measures, see page 12.

## Company Sector

Electric Utilities

## Company Description

Duke Energy Corporation operates as a regulated utility company in the US based in Charlotte, NC. The company operates regulated electric utilities in the Midwest, Florida and the Carolinas and supplies electric service to approximately 7.5 million residential, commercial, and industrial customers. Duke owns 50,000MW of capacity. The regulated gas utilities serve more than 1.6 million customers in the Carolinas and Ohio. A commercial arm owns contract renewables and pipelines across the US.

## Investment Rationale

We see current binary risk tied to ACP as a key item that will likely weigh on shares, longer-term growth initiatives could be impeded with further delays. While DUK has the potential for a grid modernization rider in N.C., we see the potential for a change in the commission as concerning. Meanwhile, SC data points are particularly cautious with below average ROEs and disallowance of capital. Further, execution headwinds related to coal ash recovery remain a key concern to monitor.

## Stock Data

| | |
|---|---|
| Average Daily Volume | 3,525,019 |

## Quarterly Earnings Estimates

| | 2018 | 2019 |
|---|---|---|
| Q1 | 1.66A | 1.24A |
| Q2 | 0.92A | 1.12A |
| Q3 | 1.65A | 1.79A |
| Q4 | 0.84A | 0.90E |

## DUK 2020 EPS walk: what to watch for?

We forecast 2020 EPS of $5.18 compared to consensus estimates of $5.14 with a range of $5.10-5.30. While the company should benefit from the implementation of rates, it still has large rate case risks in front of it in both IN (expected to be fully litigated) and in its largest jurisdiction in NC (where there are three untested commissioners).

- **Key drivers**: Positive YoY drivers include the implementation of rates and riders at the electric utilities (+$0.70), load growth (+$0.02), the reversal of storm costs (+$0.04), new rates at the Gas LDCs (+$0.10), AFUDC on Atlantic Coast Pipeline (+$0.07). Partially offsetting results are higher D&A (-$0.30), higher utility interest expense (-$0.15), incremental parent interest expense drag (-$0.02), the full-year impact of the preferred (-$0.02), and share dilution (-$0.09).

- **Unknowns**: A key question is whether the company will decided to increase its commercial renewable target, which would likely be perceived as cautious given the upfront recognition of tax credits to fill earnings divots elsewhere. For now we assume flat contribution YoY. An increase in renewable targets could also appear to coincide with an extension in the amortizable period for the ITC: hence increase in capex while keeping the earnings targets still in the same ~$200 mn/yr range.

**Table 2: DUK 2020 EPS Walk**

| DUK 2020 earnings walk | Range | EPS |
|---|---|---|
| 2019 Guidance (assume midpoint of original guide) | | 5.00 |
| *Weather* | | |
| Weather Changes | | ($0.16) |
| *Electric Utilities & Infrastructure* | | |
| O&M flat + reversal of storm expense | | $0.04 |
| Rate cases | | $0.70 |
| *Gas Utilities & Infrastructure* | | |
| Rate cases | | $0.10 |
| ACP AFUDC | | $0.07 |
| LDC growth | | $0.02 |
| *Other Utility Drag* | | |
| D&A | | ($0.30) |
| Utility Interest expense | | ($0.15) |
| *Commercial Renewables* | | |
| New projects (assume flat - could we see step-up?) | | $0.00 |
| *Parent & Other* | | |
| Holding Company Debt | | ($0.02) |
| Preferred | | ($0.02) |
| Dilution | | ($0.09) |
| DUK 2020 BofAe Adjusted EPS | | $5.18 |
| DUK 2020 BofAe EPS Guidance Range | | 5.10-5.30 |
| 2020 Consensus | | $5.14 |
| y/y growth | | 3.7% |
| Share count | | |
| 2019 Share count | | 729 |
| 2020 Share count | | 742 |

Source: BofA Global Research estimates, company report, Bloomberg

## Coal ash and NC rate case risk

DUK recently reached a resolution with the Department of Environmental Quality (DEQ) on coal ash excavation with costs reduced by $1.5bn to $2.5-3.5bn for remaining basins and 400-500mn of spend associated with coal ash expected to be included over the roll forward period (2020-2024) beyond ~$2bn in plan (coal ash only from environmental slide) for '19-'23 (quite palatable increase vs. DUK overall). The key question remains recovery of any associated capital spending & return on capital. While addressed in the last case and again pending still today before the Supreme Court, we anticipate any resolution in the current NC rate cases (and/or concurrent resolution of litigation) will prove critical (particularly relevant given total quantum of spend still contemplated).

### Examining the EPS at risk and delta between return parameters

Dialogue with the company and parties remains ongoing and ability to navigate a successful outcome in the rate case process where past precedent was for a return on/of capital (WACC) remains an uncertainty. Below, we highlight the total capital expenditures for coal ash spending as well as our assumptions for coal ash rate base. Recall, Duke Energy Progress (DEP) and Duke Energy Carolina (DEC) had ~$242mn and $546mn placed into rates with spending through 2017. For the allocation, we assume 60% for NC at DEP with 30% for wholesale that is recovered from wholesale customers as the money is spent and 10% for SC. Similarly, the allocation for DEC is ~66% NC, 10% wholesale, and 24% for SC. For 2019, we assume coal ash specific spend as a proportion of total environmental spending with the remaining $2.1bn (including the $400-500mn of additional spend) spread ratably through the 2020-2024 outlook. Current allowed return is for a WACC, although capital earns a debt-like return until placed in rates, explaining the step-up from 4% to ~7% in 2018 (we continue to assume the 7% WACC rate throughout for simplicity) In total, we see $0.26 of cumulative EPS at risk using a WACC of ~7% (see table below).

While we see it less likely that total spending would be shareholder expensed, the key question is whether an outcome in the rate case would result in a write-down or more punitive return parameters (such as a debt-like return). Below, we also highlight the delta between different return parameters, comparing ROE vs WACC (given coal ash crowds out other spending initiatives) and WACC vs debt-like return (a potential outcome in the case).

### Relationship w/ DEQ critical for clean energy agenda

Following DEQ settlement, we see a constructive relationship between the two parties as critical to the Governor's clean energy plan. *The DEQ will now be the lead agency in implementing the Clean Energy plan with potential for further delineation of coal retirements, renewable targets, grid modernization investments, and alternative regulation, among other items.* However, the plan is not likely to be implemented until 2021 as a report is not expected to be due until the end of 2020; this process with the DEQ should provide clues as to magnitude of incremental opportunity but is not required to achieve its 4-6% EPS outlook. Moreover, we wouldn't expect any legislation this year to tackle these issues given the short session. The Clean Energy plan could potentially result in upside to spending but it remains too early to predict what priorities will come out of the plan and how much incremental investment DUK can capture. Mgmt. stresses that this is not necessarily needed to maintain the 4-6% EPS growth guidance, although having a more constructive relationship with the DEQ where the issues in the court are now to the wayside could result in a more constructive dialogue going forward.

### Untested commissioners in NC also present risk to the outlook

With three untested commissioners at the North Carolina Utility Commission (NCUC) risks remain to both a constructive outcome in the rate case as well as coal ash recovery. While the Piedmont was able to receive a 9.7% ROE, the new commissioners were not on the case. Given this uncertainty, NC remains the most critical piece to the story in 2H20.

**Table 1: DUK Coal Ash rate base assumptions and total EPS at risk through forecast period**

| DUK Coal Ash Recovery | | 2015A | 2016A | 2017A | 2018A | 2019E | 2020E | 2021E | 2022E | 2023E | 2024E |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal Ash Capital Expenditures | Allocation | | | | | | | | | | |
| NC | 60% | 81 | 81 | 81 | 117 | 230 | 155 | 155 | 155 | 155 | 155 |
| Wholesale | 30% | 40 | 40 | 40 | 59 | 115 | 78 | 78 | 78 | 78 | 78 |
| SC | 10% | 13 | 13 | 13 | 20 | 38 | 26 | 26 | 26 | 26 | 26 |
| DEP | | 134 | 134 | 134 | 195 | 383 | 259 | 259 | 259 | 259 | 259 |
| NC | 66% | 182 | 182 | 182 | 152 | 208 | 107 | 107 | 107 | 107 | 107 |
| Wholesale | 10% | 28 | 28 | 28 | 23 | 31 | 16 | 16 | 16 | 16 | 16 |
| SC | 24% | 44 | 44 | 44 | 36 | 50 | 26 | 26 | 26 | 26 | 26 |
| DEC | | 276 | 276 | 276 | 230 | 315 | 162 | 162 | 162 | 162 | 162 |
| North Carolina Coal Ash Rate Base Assumptions | | | | | | | | | | | |
| Beginning Coal Ash Rate Base | | | 263 | 473 | 641 | 782 | 1,063 | 1,113 | 1,153 | 1,185 | 1,210 |
| Total NC Capital | | | 263 | 263 | 269 | 437 | 263 | 263 | 263 | 263 | 263 |
| Amortization | | | (53) | (95) | (128) | (156) | (213) | (223) | (231) | (237) | (242) |
| Ending Coal Ash Rate Base | | | 473 | 641 | 782 | 1,063 | 1,113 | 1,153 | 1,185 | 1,210 | 1,231 |
| Average Rate Base | | | 368 | 557 | 711 | 922 | 1,088 | 1,133 | 1,169 | 1,197 | 1,220 |
| Equity Cap | | 53% | 53% | 53% | 52% | 52% | 52% | 52% | 52% | 52% | 52% |
| EPS Assumptions for coal ash recovery | | | 2016A | 2017A | 2018A | 2019E | 2020E | 2021E | 2022E | 2023E | 2024E |
| Allowed Return (Debt then WACC once in rates) | | | $0.01 | $0.02 | $0.03 | $0.04 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 |
| *S/O* | | | *692* | *700* | *708* | *729* | *742* | *769* | *774* | *780* | *786* |
| Cumulative EPS at Risk 2020-2024 | | | | | | | | | | | $0.26 |
| EPS Scenarios under different return parameters | | | | | | | | | | | |
| Return Parameters | | | | | | | | | | | |
| Debt-like Return | | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% | 4% |
| Allowed Return (Debt then WACC once in rates) | | 4% | 4% | 4% | 7% | 7% | 7% | 7% | 7% | 7% | 7% |
| ROE | | 9.9% | 9.9% | 9.9% | 9.9% | 9.9% | 9.9% | 9.9% | 9.9% | 9.9% | 9.9% |
| EPS | | | | | | | | | | | |
| Debt-like Return | | | $0.01 | $0.01 | $0.02 | $0.02 | $0.03 | $0.03 | $0.03 | $0.03 | $0.03 |
| ROE | | | $0.03 | $0.04 | $0.05 | $0.07 | $0.08 | $0.08 | $0.08 | $0.08 | $0.08 |
| Delta | | | | | | | | | | | |
| Debt return vs ROE | | | ($0.02) | ($0.03) | ($0.03) | ($0.04) | ($0.05) | ($0.05) | ($0.05) | ($0.05) | ($0.05) |
| Shareholder expensed vs WACC | | | ($0.01) | ($0.02) | ($0.03) | ($0.04) | ($0.05) | ($0.05) | ($0.05) | ($0.05) | ($0.05) |
| WACC vs ROE | | | ($0.02) | ($0.02) | ($0.02) | ($0.02) | ($0.02) | ($0.02) | ($0.03) | ($0.03) | ($0.03) |
| Debt return vs WACC *(could NC rate result in this scenario?)* | | | ($0.00) | ($0.00) | ($0.02) | ($0.02) | ($0.02) | ($0.02) | ($0.02) | ($0.03) | ($0.03) |

Source: BofA Global Research estimates, company report,

## IN: Settlement not likely but support for Edwardsport?

In Indiana, we see a settlement as less likely given hearings are slated to start on Jan 22 with the window for settlement to be filed closing quickly. DUK's Edwardsport plant has maintained full support from the state, including the governor, statehouse, and commissioners, despite efforts opposing it. We see DUK's effort to roll the plant into full rates as proceeding with state support. Stakeholders we spoke to in IN generally see limited risk in terms of the likelihood of the inclusion of the asset in rates, although it could be further litigated outside of the rate case. We expect full recovery in the rate case regardless of recent scrutiny, helping to de-risk this case somewhat. Nonetheless, with other critical issues to tackle including coal retirements, coal ash, and grid modernization, we could see a drop in authorized ROE akin to latest NI case to 9.75% (from 9.95%).

## Renewables: will mgmt. increase the outlook?

The renewable earnings outlook and spending levels are likely the most near-term risk to the story. The company has increased confidence in its renewable development program given line of sight to majority of needs through the forecast period and with numerous projects exceeding hurdle rates. The question is whether mgmt. will yet further increase the earnings outlook. We are cautious on the blended earnings quality of these assets given the immediate step-up in earnings recognition from Investment Tax Credits (ITCs), which will eventually result in a cliff as tax credits are due to expire. Half of this business is from legacy wind assets which have a more extended timeline. ITCs are expected to be taken on a very short duration basis with all of the earnings power of assets effectively accelerated into the initial years of the structure. With questions over the potential degradation of earnings in the core utility business, we believe a step-up in earnings for commercial renewables would be perceived poorly unless mgmt. can clearly articulate it is incremental rather than filling a gap. Critical to whether mgmt increases its renewable net income contributions will be how this is characterized; is this *incremental* to the outlook or *does this simply affirm the 4-6% EPS growth outlook and implicitly replace existing earnings assumptions on core utilities?*

## FL and OH: could prove constructive to 4Q update

In FL, recently passed undergrounding legislation appears to be a tailwind to the $1.6bn on average annualized spending of in the state. We see this as consistent with efforts by EMA with their 4Q results to stress upside in FL as well on grid hardening alongside solar too. Mgmt. is in a multi-year rate plan that runs through 2021. We would expect the company to file sometime in 2020 in order to reset the plan with additional investments to come in '22 and beyond. Unclear of the exact magnitude given the company spends $400-500mn in FL on undergrounding currently, although we view it as positive on the margin. Meanwhile, HB247 in OH could allow for behind the meter generation investment opportunities, although clarity on this too could linger into 2020.

## DUK 4Q19 EPS walk

We forecast 4Q19 EPS of $0.90 compared to 4Q18 results of $0.84 and consensus estimates of $0.87. While the quarter will help take results toward the mid-point for 2019, it's aided in part by incremental commercial renewable contribution as well as reversal of storm expenses.

- **Key drivers**: Positive YoY drivers include the implementation of rates and riders at the electric utilities (+$0.10), load growth (+$0.03), the reversal of storm costs (+$0.05), new rates at Piedmont (+$0.02), AFUDC on Atlantic Coast Pipeline (+$0.02), and the contribution from the Lapetus and Palmer commercial renewable projects (+$0.05). Partially offsetting results are regulatory lag (-$0.04), the timing of O&M (-$0.05), lower AFUDC equity (-$0.01), higher utility interest expense (-$0.01), higher parent interest expense (-$0.01), and share dilution (-$0.01).

- **Unknowns**: Weather is expected to be unfavorable driver in the quarter with HDDs below the norm and the exact magnitude is unclear. Further, we would expect the company to pull ahead O&M costs forward given the favorable benefits of weather to date (+$0.17), although its difficult to predict just how much the company will spend on these initiatives.

**Table 3: DUK 4Q19 EPS Walk**

| DUK 4Q19 Earnings Walk | EPS |
|---|---|
| DUK 4Q18 EPS | 0.84 |
| Weather - normalize from 4Q18 | -$0.06 |
| Weather- 4Q19 | -$0.01 |
| Electric | $0.02 |
| Rate implementation: | |
| DEC SC rates (full quarter) | $0.01 |
| DEP SC rates (full quarter) | $0.01 |
| Ohio | $0.01 |
| Florida - multi-year plan | $0.01 |
| Citrus County | $0.02 |
| SOBRA - FL | $0.01 |
| Other Riders - IN, OH | $0.02 |
| Regulatory lag | -$0.04 |
| Load Growth - 0.5% | $0.02 |
| O&M timing | -$0.05 |
| Storm O&M | $0.02 |
| AFUDC equity | -$0.01 |
| Interest Exp | -0.01 |
| Gas | $0.05 |
| LDC Growth | $0.01 |
| New Rates | $0.02 |
| AFUDC for ACP | $0.02 |
| Renewables | $0.05 |
| Lapetus & Palmer (160MW) | $0.05 |
| Other | $0.01 |
| Parent Interest expense | -$0.01 |
| Other | $0.00 |
| Storm O&M | $0.03 |
| Dilution | -$0.01 |
| DUK 4Q BofAe Adjusted EPS | $0.90 |
| Consensus | $0.87 |
| BofAe 2019 EPS | 5.05 |
| Guidance | 4.95-5.15 |
| 2019 Consensus | 4.95 |
| DUK 4Q19 Shares Outstanding | 729 |
| DUK 4Q18 Shares Outstanding | 716 |
| Tax Rate | 14% |

Source: BofA Global Research estimates, company report, Bloomberg

## EPS Estimates

We provide our latest EPS assumptions below where we slightly increase our assumptions based on expectations for 2020 and beyond, although still remain at the low-end of the company's 4-6% EPS growth trajectory. This includes substantial tax credits in earnings, which remain of lower quality given ITCs eventually roll-off. Project risk for ACP is also a material concern as the 14% AFUDC rate will step down material if in-service or result in a more draconian outcome if canceled. Bottom line, the deterioration of earnings quality remains among the single biggest factor for shares; we perceive the outcome of the 4Q reporting as critical to shifting sentiment on shares after its latest under-performance. Given multiple (larger) rate cases this year, we see composition of '20 as key given last year's surprise implicit guide down on core earnings power (ex-renewable 1x benefits).

**Table 4: DUK EPS Estimates**

| EPS Estimates | 2018A | 2019E | 2020E | 2021E | 2022E | 2023E |
|---|---|---|---|---|---|---|
| Electric | | | | | | |
| Carolinas | 1.65 | 1.75 | 1.73 | 1.74 | 1.79 | 1.85 |
| Indiana | 0.57 | 0.61 | 0.62 | 0.63 | 0.66 | 0.68 |
| Ohio - Electric | 0.26 | 0.28 | 0.31 | 0.34 | 0.37 | 0.43 |
| Progress- Carolinas | 1.02 | 1.11 | 1.13 | 1.15 | 1.18 | 1.22 |
| Progress- Florida | 0.81 | 0.95 | 0.98 | 1.01 | 1.07 | 1.12 |
| Commercial Transmission | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Eliminations | 0.39 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Consolidated Earnings | 4.70 | 4.71 | 4.77 | 4.87 | 5.07 | 5.31 |
| Guidance | | 4.77 | | | | |
| Gas | | | | | | |
| Ohio - Gas | 0.13 | 0.12 | 0.14 | 0.14 | 0.15 | 0.16 |
| Piedmont (PNY) | 0.23 | 0.29 | 0.30 | 0.32 | 0.35 | 0.39 |
| Midstream Pipelines | 0.02 | 0.21 | 0.23 | 0.30 | 0.30 | 0.27 |
| Eliminations | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Consolidated Earnings | 0.45 | 0.62 | 0.67 | 0.77 | 0.81 | 0.82 |
| Guidance | | 0.51 | | | | |
| Commercial Renewables | 0.14 | 0.31 | 0.29 | 0.28 | 0.27 | 0.28 |
| Guidance | | 0.32 | | | | |
| Parent/Other | -0.57 | -0.59 | -0.55 | -0.51 | -0.50 | -0.50 |
| Guidance | | -0.60 | | | | |
| Adjustments | | | | | | |
| BofAe EPS | 4.72 | 5.05 | 5.18 | 5.41 | 5.65 | 5.91 |
| *Previous Estimates* | | *5.00* | *5.13* | *5.36* | *5.62* | *5.89* |
| Guidance | 4.65-4.85 | *4.95-5.15* | | | | |
| Consensus | 4.76 | 5.01 | 5.14 | 5.38 | 5.69 | 6.00 |
| Mgmt EPS CAGR: 4-6% from 2019-2023E | | 5.00 | 5.25 | 5.51 | 5.79 | 6.08 |
| *Low End* | | 4.80 | 5.20 | 5.41 | 5.62 | 5.85 |
| *High End* | | 5.20 | 5.30 | 5.62 | 5.96 | 6.31 |
| | | | | | | |
| BofAe CAGR '19-'23e | | | | | | 4.3% |

Source: BofA Global Research estimates, company report, Bloomberg

## Valuation: PO to $96

We move our PO to $96 (from $95) on our latest estimates and mark-to-market of peer utility multiples of 18.8x for electric (from 18.7x) and 18.8x for gas (from 18.3x). While we see some upside in shares based on our SOTP analysis, we see limited catalyst over the near-term that would warrant a multiple re-rating. ACP could have a lower weighting applied than the 50% we give credit for given continued uncertainty, and still see lingering concerns with twin NC rate case and coal ash risks as well as a an expected fully litigated case in IN. We continue to see core earnings as remaining riskier.

**Table 5: DUK EPS Estimates**

Duke Energy Sum of the Parts Valuation
2022E
All figures in $Mn except per share

| | Metric | P/E Multiple | | | | | | Equity Value | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2022 EPS | Low | Peer | Prem/ Discount | Base | High | - | Low | Base | High |
| Group Peer Multiple - Electric | - | - | 18.8x | - | - | - | - | - | - | - |
| Group EPS '18-'22 CAGR - Electric | - | - | 5.00% | - | - | - | - | - | - | - |
| | - | - | - | - | - | - | - | - | - | - |
| Electric Utilities | | | 19.7x | | | | | | | |
| Duke Energy Carolinas | $1.79 | 18.7x | | 0.0x | 19.7x | 20.7x | | $33.52 | $35.30 | $37.09 |
| Duke Energy Progress/Carolinas | $1.18 | 18.7x | | 0.0x | 19.7x | 20.7x | | $22.03 | $23.20 | $24.38 |
| Duke Energy Florida | $1.07 | 19.7x | | 1.0x | 20.7x | 21.7x | | $21.13 | $22.20 | $23.27 |
| Duke Energy Indiana | $0.66 | 18.7x | | 0.5x | 19.7x | 20.7x | | $12.66 | $13.32 | $13.98 |
| Duke Energy Ohio/Kentucky | $0.37 | 18.7x | | 0.0x | 19.7x | 20.7x | | $6.99 | $7.36 | $7.73 |
| Total Electric Utility Value | $5.06 | | | | | | | $96.32 | $101.38 | $106.45 |
| | | | | | | | | | | |
| Group Peer Multiple - Gas | | | 18.9x | | | | | | | |
| Group EPS '18-'22 CAGR - Gas | | | 5.10% | | | | | | | |
| | | | | | | | | | | |
| Gas Utilities | 2022 EPS | | 19.9x | | | | | | | |
| Duke Energy Piedmont | $0.35 | 18.9x | | 0.0x | 19.9x | 20.9x | | $6.68 | $7.04 | $7.39 |
| Duke Energy Ohio/Kentucky Gas | $0.15 | 18.9x | | 0.0x | 19.9x | 20.9x | | $2.90 | $3.05 | $3.21 |
| Total Gas Utility Value | $0.51 | | | | | | | $9.58 | $10.09 | $10.60 |
| | | | | | | | | | | |
| Commercial Segment | 2022 EBITDA | | | | | | | | | |
| Midstream Infrastructure: | | | | | | | Weight | | | |
| ACP | $472 | 10.0x | 11.0x | 0.0x | 11.0x | 12.0x | 50% | 2,359 | 2,595 | 2,831 |
| Add back ACP debt | | | | | | | 50% | 808 | 808 | 808 |
| | | | | | | | | | | |
| All Other | $61 | 10.0x | 11.0x | 0.0x | 11.0x | 12.0x | | 614 | 676 | 737 |
| Transmission Segment | $6 | 10.0x | 11.0x | 0.0x | 11.0x | 12.0x | | 64 | 71 | 77 |
| Segment Net Debt | -$4,851 | | | | | | | -4,851 | -4,851 | -4,851 |
| Add back Renewable Debt | $1,088 | | | | | | | 1,088 | 1,088 | 1,088 |
| Renewables Segment NPV @ 8% Discount | $1,291 | | | | | | | 1,291 | 1,291 | 1,291 |
| New Renewables NPV | $369 | | | | | | | 369 | 369 | 369 |
| Net Infrastructure Equity | | | | | | | | 1,743 | 2,047 | 2,351 |
| Net Infrastructure Equity Per Share | | | | | | | | $2.39 | $2.64 | $3.23 |
| | | | | | | | | | | |
| Parent | 2022 EPS | | | | | | | | | |
| NMC (Saudi Chemical JV) | $0.05 | 12.7x | | -6.0x | 13.7x | 14.7x | | $0.64 | $0.69 | $0.74 |
| | | | | | | | | | | |
| Parent Interest attributed to utility - 50% | -$0.50 | 20.9x | | 0.0x | 19.9x | 18.9x | | -$5.25 | -$5.00 | -$4.75 |
| Parent Debt- 50% | -$21,175 | | | | | | | -$13.67 | -$13.67 | -$13.67 |
| Total Equity Value | | | | | | | | -$18.28 | -$17.98 | -$17.68 |
| | | | | | | | | | | |
| Shares Outstanding | | | | | | | | | 774 | |
| Total Equity Value | | | | | | | | $90.00 | $96.00 | $103.00 |
| Current Share Price | | | | | | | | $90.93 | $90.93 | $90.93 |
| NTM Dividend Yield | | | | | | | | | 4.21% | |
| Total Return | | | | | | | | | 9.78% | |

Source: BofA Global Research estimates, company report, Bloomberg

## Price objective basis & risk

**Duke Energy (DUK)**

Our $96 PO is derived from a sum-of-the-parts valuation. We value the Electric and Gas utilities using peer 2022E P/E multiples. We apply a 1.0x multiple premium to Duke's operations in Florida to reflect more favorable regulatory environments. We apply an in-line multiple to the Carolinas given risk ahead. We value the other regulated electric utilities and the gas utilities at peer group multiples of 18.8x and 18.9x 2022E P/E, respectively. Both electric and gas peer P/E multiples are grossed up by 5% for the groups CAGR to reflect capital appreciation across the sector. The commercial midstream, and transmission are valued on a 2022E EV/EBITDA basis. We use a 11.0x multiple for midstream and transmission segment, although we assume a 50% weighting for ACP given risks to completion. We add the net present value of renewable segment using an 8% discount rate. We subtract out the impact of commercial debt, and add back for the renewable debt.

Upside risks: constructive rate case results, higher capital expenditure additions vs our assumptions, ACP ahead of schedule, lower interest rates. Downside risks: poor rate case results, operating errors, and negative changes in the regulatory environment, ACP delays. Macro risks: Increases in interest rates and decreases in equity market valuations.

## Analyst Certification

I, Julien Dumoulin-Smith, hereby certify that the views expressed in this research report accurately reflect my personal views about the subject securities and issuers. I also certify that no part of my compensation was, is, or will be, directly or indirectly, related to the specific recommendations or view expressed in this research report.

**North American Utilities, Alternative Energy & LNG Coverage Cluster**

| Investment rating | Company | BofA Ticker | Bloomberg symbol | Analyst |
|---|---|---|---|---|
| BUY | | | | |
| | Alliant Energy Corporation | LNT | LNT US | Julien Dumoulin-Smith |
| | AltaGas | YALA | ALA CN | Julien Dumoulin-Smith |
| | Ameren Corporation | AEE | AEE US | Julien Dumoulin-Smith |
| | American Electric Power | AEP | AEP US | Julien Dumoulin-Smith |
| | Aqua America | WTR | WTR US | Julien Dumoulin-Smith |
| | Atlantica Yield | AY | AY US | Julien Dumoulin-Smith |
| | Atmos Energy Corporation | ATO | ATO US | Richard Ciciarelli, CFA |
| | Black Hills Corporation | BKH | BKH US | Julien Dumoulin-Smith |
| | Cheniere Energy Inc | LNG | LNG US | Julien Dumoulin-Smith |
| | Clearway Energy | CWENA | CWEN/A US | Julien Dumoulin-Smith |
| | Clearway Energy | CWEN | CWEN US | Julien Dumoulin-Smith |
| | CMS Energy | CMS | CMS US | Julien Dumoulin-Smith |
| | Emera Inc | YEMA | EMA CN | Julien Dumoulin-Smith |
| | Entergy | ETR | ETR US | Julien Dumoulin-Smith |
| | Exelon | EXC | EXC US | Julien Dumoulin-Smith |
| | First Solar, Inc. | FSLR | FSLR US | Julien Dumoulin-Smith |
| | NextEra Energy | NEE | NEE US | Julien Dumoulin-Smith |
| | NiSource Inc | NI | NI US | Julien Dumoulin-Smith |
| | NRG Energy | NRG | NRG US | Julien Dumoulin-Smith |
| | OGE Energy Corp | OGE | OGE US | Julien Dumoulin-Smith |
| | PNM Resources Inc. | PNM | PNM US | Julien Dumoulin-Smith |
| | Portland General Electric Company | POR | POR US | Julien Dumoulin-Smith |
| | Spire | SR | SR US | Richard Ciciarelli, CFA |
| | Sunnova Energy | NOVA | NOVA US | Julien Dumoulin-Smith |
| | SunRun | RUN | RUN US | Julien Dumoulin-Smith |
| | Vistra Energy | VST | VST US | Julien Dumoulin-Smith |
| | Vivint Solar | VSLR | VSLR US | Julien Dumoulin-Smith |
| NEUTRAL | | | | |
| | AES | AES | AES US | Julien Dumoulin-Smith |
| | Algonquin Power & Utilities Corp | AQN | AQN US | Julien Dumoulin-Smith |
| | Algonquin Power & Utilities Corp | YAQN | AQN CN | Julien Dumoulin-Smith |
| | CenterPoint Energy | CNP | CNP US | Julien Dumoulin-Smith |
| | Consolidated Edison | ED | ED US | Julien Dumoulin-Smith |
| | Dominion Energy | D | D US | Julien Dumoulin-Smith |
| | DTE Energy | DTE | DTE US | Julien Dumoulin-Smith |
| | Edison International | EIX | EIX US | Julien Dumoulin-Smith |
| | FirstEnergy | FE | FE US | Julien Dumoulin-Smith |
| | Fortis | YFTS | FTS CN | Julien Dumoulin-Smith |
| | Fortis Inc | FTS | FTS US | Julien Dumoulin-Smith |
| | Hannon Armstrong | HASI | HASI US | Julien Dumoulin-Smith |
| | Idacorp | IDA | IDA US | Julien Dumoulin-Smith |
| | NextDecade | NEXT | NEXT US | Julien Dumoulin-Smith |
| | NextEra Energy Partners | NEP | NEP US | Julien Dumoulin-Smith |
| | Pinnacle West | PNW | PNW US | Julien Dumoulin-Smith |
| | PPL Corporation | PPL | PPL US | Julien Dumoulin-Smith |
| | Public Service Enterprise Group | PEG | PEG US | Julien Dumoulin-Smith |
| | Sempra Energy | SRE | SRE US | Julien Dumoulin-Smith |
| | Southern Company | SO | SO US | Julien Dumoulin-Smith |
| | Tellurian Inc | TELL | TELL US | Julien Dumoulin-Smith |
| UNDERPERFORM | | | | |
| | American Water Works | AWK | AWK US | Julien Dumoulin-Smith |
| | Avangrid | AGR | AGR US | Julien Dumoulin-Smith |
| | Avista | AVA | AVA US | Richard Ciciarelli, CFA |
| | Bloom Energy | BE | BE US | Julien Dumoulin-Smith |
| | Duke Energy | DUK | DUK US | Julien Dumoulin-Smith |
| | Evergy, Inc | EVRG | EVRG US | Julien Dumoulin-Smith |
| | Eversource Energy | ES | ES US | Julien Dumoulin-Smith |
| | Hawaiian Electric Industries | HE | HE US | Julien Dumoulin-Smith |
| | NorthWestern Corporation | NWE | NWE US | Julien Dumoulin-Smith |
| | SunPower Corp. | SPWR | SPWR US | Julien Dumoulin-Smith |
| | Terraform Power | TERP | TERP US | Julien Dumoulin-Smith |
| | Unitil Corporation | UTL | UTL US | Julien Dumoulin-Smith |
| | WEC Energy Group Inc | WEC | WEC US | Julien Dumoulin-Smith |
| | Xcel Energy Inc | XEL | XEL US | Julien Dumoulin-Smith |

**North American Utilities, Alternative Energy & LNG Coverage Cluster**

| Investment rating | Company | BofA Ticker | Bloomberg symbol | Analyst |
|---|---|---|---|---|
| RSTR | | | | |
| | El Paso Electric Company | EE | EE US | Julien Dumoulin-Smith |
| | Pattern Energy Group | PEGI | PEGI US | Julien Dumoulin-Smith |

***iQ***method[SM] **Measures Definitions**

| Business Performance | Numerator | Denominator |
|---|---|---|
| Return On Capital Employed | NOPAT = (EBIT + Interest Income) * (1 - Tax Rate) + Goodwill Amortization | Total Assets – Current Liabilities + ST Debt + Accumulated Goodwill Amortization |
| Return On Equity | Net Income | Shareholders' Equity |
| Operating Margin | Operating Profit | Sales |
| Earnings Growth | Expected 5-Year CAGR From Latest Actual | N/A |
| Free Cash Flow | Cash Flow From Operations – Total Capex | N/A |
| **Quality of Earnings** | | |
| Cash Realization Ratio | Cash Flow From Operations | Net Income |
| Asset Replacement Ratio | Capex | Depreciation |
| Tax Rate | Tax Charge | Pre-Tax Income |
| Net Debt-To-Equity Ratio | Net Debt = Total Debt, Less Cash & Equivalents | Total Equity |
| Interest Cover | EBIT | Interest Expense |
| **Valuation Toolkit** | | |
| Price / Earnings Ratio | Current Share Price | Diluted Earnings Per Share (Basis As Specified) |
| Price / Book Value | Current Share Price | Shareholders' Equity / Current Basic Shares |
| Dividend Yield | Annualised Declared Cash Dividend | Current Share Price |
| Free Cash Flow Yield | Cash Flow From Operations – Total Capex | Market Cap. = Current Share Price * Current Basic Shares |
| Enterprise Value / Sales | EV = Current Share Price * Current Shares + Minority Equity + Net Debt + Other LT Liabilities | Sales |
| EV / EBITDA | Enterprise Value | Basic EBIT + Depreciation + Amortization |

*iQmethod* [SM] is the set of BofA Global Research standard measures that serve to maintain global consistency under three broad headings: Business Performance, Quality of Earnings, and validations. The key features of iQmethod are: A consistently structured, detailed, and transparent methodology. Guidelines to maximize the effectiveness of the comparative valuation process, and to identify some common pitfalls.

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# Disclosures

## Important Disclosures

**Duke Energy (DUK) Price Chart**


B: Buy, N: Neutral, U: Underperform, PO: Price Objective, NA: No longer valid, NR: No Rating

The Investment Opinion System is contained at the end of the report under the heading "Fundamental Equity Opinion Key". Dark grey shading indicates the security is restricted with the opinion suspended. Medium grey shading indicates the security is under review with the opinion withdrawn. Light grey shading indicates the security is not covered. Chart is current as of a date no more than one trading day prior to the date of the report.

**Equity Investment Rating Distribution: Utilities Group (as of 31 Dec 2019)**

| Coverage Universe | Count | Percent | Inv. Banking Relationships* | Count | Percent |
|---|---|---|---|---|---|
| Buy | 63 | 44.06% | Buy | 44 | 69.84% |
| Hold | 43 | 30.07% | Hold | 31 | 72.09% |
| Sell | 37 | 25.87% | Sell | 27 | 72.97% |

**Equity Investment Rating Distribution: Global Group (as of 31 Dec 2019)**

| Coverage Universe | Count | Percent | Inv. Banking Relationships* | Count | Percent |
|---|---|---|---|---|---|
| Buy | 1560 | 50.49% | Buy | 991 | 63.53% |
| Hold | 717 | 23.20% | Hold | 461 | 64.30% |
| Sell | 813 | 26.31% | Sell | 415 | 51.05% |

* Issuers that were investment banking clients of BofA Securities or one of its affiliates within the past 12 months. For purposes of this Investment Rating Distribution, the coverage universe includes only stocks. A stock rated Neutral is included as a Hold, and a stock rated Underperform is included as a Sell.

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| Investment rating | Total return expectation (within 12-month period of date of initial rating) | Ratings dispersion guidelines for coverage cluster* |
|---|---|---|
| Buy | ≥ 10% | ≤ 70% |
| Neutral | ≥ 0% | ≤ 30% |
| Underperform | N/A | ≥ 20% |

* Ratings dispersions may vary from time to time where BofA Global Research believes it better reflects the investment prospects of stocks in a Coverage Cluster.

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Price charts for the securities referenced in this research report are available at https://pricecharts.baml.com, or call 1-800-MERRILL to have them mailed.
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# YOUNG REBUTTAL EXHIBIT NO. 6

WOLFE RESEARCH

**UTILITIES & POWER**

***Regulateds – Market Underweight***
***Integrateds – Market Overweight***
***IPPs – Market Overweight***
***Gas/Power Infrastructure – Market Overweight***

February 13, 2020

# DUKE ENERGY

(DUK US Equity – $100.11 – Peer Perform)

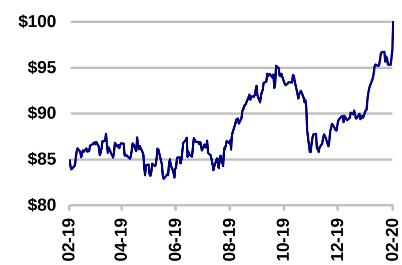
## *Trying to reDuke the critics*

- **Confident tone on outlook; stock bounces off lows.** On 2/13, DUK reported 2019 EPS of $5.06, beating consensus by $0.04, and gave FY20 guidance of $5.05-5.45, better than prior-consensus of $5.16 and our $5.18e. DUK extended its 4-6% EPS growth target through 2024 (off $5.00 in 2019), as its 5-yr capital plan rose to $56B from $50B. DUK stock beat the UTY by 210bp and lifted it off relative lows, as mgmt. struck a confident tone on its outlook, suggesting the growth is durable under a wide range of scenarios. Still, DUK trades at nearly a 3.5x discount to peers. While steep, we see it in a 2-3x discount range due to rate case and ACP overhangs in 1H20. Peer Perform.
- **More capex to support utility growth.** The incremental $6B is focused in the Carolinas, FL and gas LDCs. The latter two have multiyear plans or riders.
- **Rate cases key; next data point on 2/18.** NC (DUK's largest state) generally has traditional frameworks, which are susceptible to lag. Given low interest rates and high utility valuations, there could also be some pressure on ROEs in DUK's pending rate cases, including DEC and DEP in NC. Notably, DUK's NC gas utility and Dominion's NC electric utility recently received 9.7-9.75% ROEs, providing good data points for DEC/DEP (currently allowed 9.9%). Coal ash cost recovery will again be disputed, as intervenors opposed the NCUC's 2017-18 decisions allowing deferrals (with a full return) and a 5-yr recovery period. In D's recent rate case, the NCUC appeared to not allow a return to be booked over a 10-yr recovery period, which would be unfavorable if applied to DUK. Intervenor testimony in the DEC rate case is due 2/18.
- **ACP certainty by midyear.** To proceed with ACP, DUK needs permits from the FWS (expected mid-2020) and a SCOTUS ruling on crossing the Appalachian Trail (Jun 2020). If successful, ACP should resume construction in 2H20, with in-service in 2022. ACP is roughly $0.20 for DUK.
- **Raise estimates on capex; lift PT by $2 on higher group P/E.** We raised our 2020-22E by $0.01-0.06 on the new capex. Our $102 PT is based on a 2.5x discount to our group P/E of 20.5x 2022E (previously used 21.0x 2021E).

| Estimates / Valuation | | | | |
|---|---|---|---|---|
| (US$) | 2020E | 2021E | 2022E | 2023E |
| EPS | $5.19 | $5.46 | $5.69 | $5.99 |
| Consensus | $5.17 | $5.41 | $5.71 | $5.98 |
| P/E | 19.3x | 18.3x | 17.6x | 16.7x |
| Dividend Yield | 3.9% | 3.9% | 4.0% | 4.1% |

| Trading and Fundamental Data | |
|---|---|
| **Target Price** | **$ 102** |
| Current Price | 100.11 |
| 52 Week Range | $ 84 - $ 100 |
| Market Cap. ($MM) | $ 73,381 |
| Share Out. (MM) | 733.0 |
| Dividend Yield | 3.8% |
| Dividend Payout Ratio | 79% |
| ROE | 8.4% |
| Debt to Cap | 56.7% |
| Avg Daily Vol (ooo) | 2,876 |

| Price Performance | YTD | LTM |
|---|---|---|
| DUK US Equity | 10% | 12% |
| Utility Index | 8% | 26% |
| S&P 500 | 4% | 23% |




Source: FactSet/Wolfe Research

| Key Changes | | |
|---|---|---|
| (US$) | Current | Previous |
| Price target | $102 | $100 |
| 2020E EPS | $5.19 | $5.18 |
| 2021E EPS | $5.46 | $5.40 |
| 2022E EPS | $5.69 | $5.64 |
| 2023E EPS | $5.99 | NA |

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WOLFE RESEARCH

**Duke Energy**

**February 13, 2020**

# Duke Energy Snapshot

### Exhibit 1. Financial Summary

| Financial Summary | 2020E | 2021E | 2022E | 2023E |
|---|---|---|---|---|
| EPS | $5.19 | $5.46 | $5.69 | $5.99 |
| Diluted Shares Outstanding | 750 | 769 | 774 | 776 |
| Indicated Dividend Per Share | $3.86 | $3.93 | $4.01 | $4.09 |
| Dividend Yield | 3.9% | 3.9% | 4.0% | 4.1% |
| Payout Ratio | 74% | 72% | 70% | 68% |
| Equity ratio (excl ST debt) | 44% | 44% | 43% | 43% |
| FFO/Net Debt | 14% | 14% | 14% | 14% |
| **Valuation Metrics** | | | | |
| P/E | 19.3x | 18.3x | 17.6x | 16.7x |
| EV/EBITDA | 12.4x | 12.1x | 11.9x | 11.6x |
| P/B | 1.5x | 1.5x | 1.5x | 1.4x |
| FCF/Yield | (3.1)% | (1.8)% | (1.0)% | (0.9)% |
| **Segment EPS** | | | | |
| Electric | $4.85 | $5.07 | $5.28 | $5.55 |
| Gas | 0.70 | 0.75 | 0.81 | 0.84 |
| Commercial | 0.31 | 0.32 | 0.30 | 0.31 |
| Parent/Other | (0.68) | (0.67) | (0.70) | (0.71) |
| **Total EPS** | **$5.19** | **$5.46** | **$5.69** | **$5.99** |

Source: Wolfe Utilities & Power Research

### Exhibit 2. Modeling Assumptions

| | 2020E | 2021E | 2022E | 2023E |
|---|---|---|---|---|
| **Capital Spending ($M)** | | | | |
| Electric | $8,675 | $8,450 | $9,225 | $9,775 |
| Gas | 2,275 | 1,950 | 1,150 | 1,025 |
| Commercial | 550 | 600 | 400 | 300 |
| Parent/Other | 275 | 225 | 225 | 250 |
| **Total Capital Spending** | $11,775 | $11,225 | $11,000 | $11,350 |
| **Financings ($M)** | | | | |
| Total Equity Issued/(Repurchased) | $2,985 | $500 | $500 | $0 |
| Total Debt Issued/(Repurchased) | 2,679 | 3,960 | 3,325 | 3,875 |

Source: Wolfe Utilities & Power Research

## Company description

Duke Energy is headquartered in Charlotte, North Carolina and is the largest utility in the country. The company serves 7.4M electric customers in the Carolinas, FL, IN, OH and KY. DUK's Electric Infrastructure segment, which includes its electric utility subs, makes up most of earnings. DUK also has small gas LDCs in NC and the Midwest and a nonutility midstream business, which form the Gas Infrastructure segment. It serves 1.5M gas customers. DUK also has nonutility renewables investments in its Commercial business, which is expected to remain around 5% of the company.

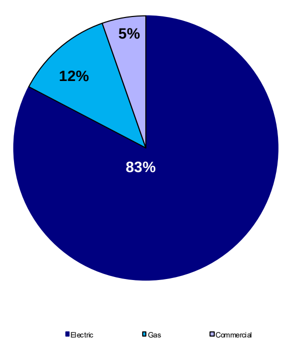
## Investment Thesis

DUK is the largest US regulated utility. Its regulatory environments are generally reasonable. EPS growth is contingent on fair regulatory treatment and execution on ACP, which awaits legal certainty midyear. NC is a key state for coal ash recovery and grid mod/resiliency spend; but DUK has two pending NC rate cases, adding regulatory uncertainty over the story near-term. DUK's dividend yield is near the top of the group, but growth is below average at about 2%/yr.

## Valuation

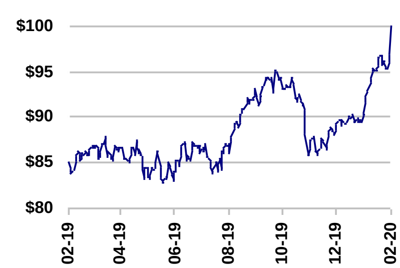
Our PT is based on a 2.5x discount to our average utility group P/E multiple of 20.5x 2022 EPS. The discount is largely due to below average earnings/dividend growth, rate case and ACP overhangs. Upside risks are incremental capex and an improving economy. Downside risks are unfavorable regulatory treatment, additional ACP delays and less capex than planned.

### Exhibit 3. 2020E EPS by Segment




Source: Wolfe Utilities & Power Research

### Exhibit 4. Performance Chart




Source: Bloomberg

## Investment thesis

DUK stock is facing rate case uncertainty in NC and IN and legal uncertainty over ACP, which are expected to last through the first half of this year. The two rate cases in its largest state (NC) are particularly important for coal ash recovery and minimizing regulatory lag, as grid mod and resiliency spend ramps up. History is on DUK's side, as NC regulators issued a reasonable order on coal ash in the last round of DUK rate cases, after parties had already reached a settlement on ROE and equity ratio. DUK's $56B of utility capex through 2024 should support 4-6% EPS growth with reasonable outcomes in its rate cases. We project some modest lag, with earned ROEs in the high 9s, and include ACP in our estimates. DUK stock bounced off its 52-week relative low but still has a lot of ground to make up (see Exhibit 5). The stock currently trades at nearly a 3.5x discount to utility peers (Exhibit 6). We see it trading at a 2-3x discount until the aforesaid overhangs begin to lift possibly by midyear. DUK's 3.8% dividend yield is the second highest among peers (behind PPL), limiting downside from current valuations.

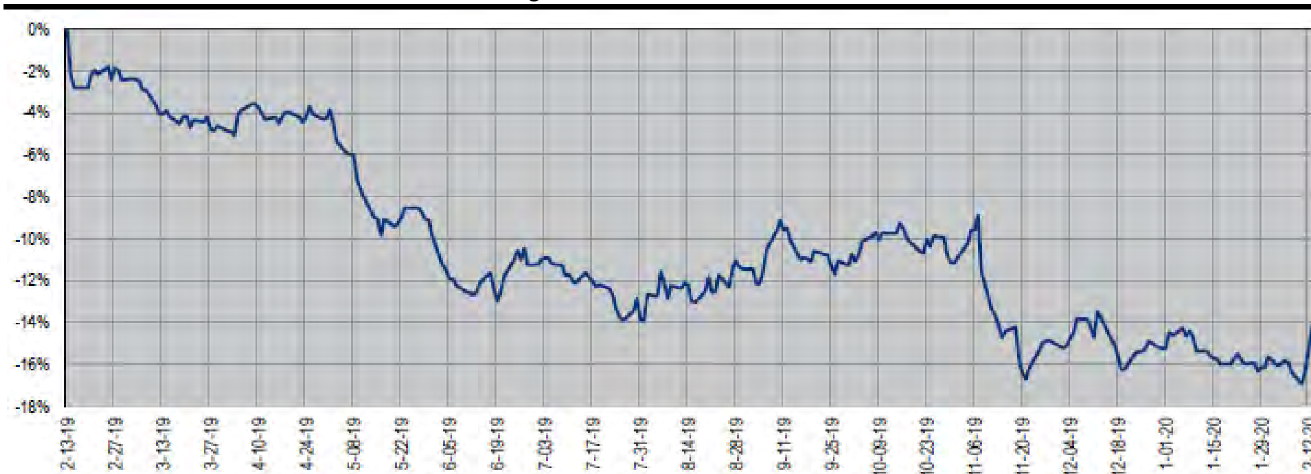
## Earnings estimate vs company

Our 2020-23E of $5.19/5.46/5.69/5.99 imply a 4.6% CAGR, below the midpoint of DUK's 4-6% EPS growth. Our 2020E estimate is below DUK's range, as we project some lag from pending rate cases and dilution from last year's roughly $2.5B forward equity deal, from which DUK will draw this year. But we estimate the incremental capex and rate relief will lift earnings in 2021. We again expect modest lag in 2022-23, but rate base growth continues to push EPS growth in the 4-5% range. Our estimates assume ACP is in-service in 2022; ACP is about $0.20 of earnings. And we project Commercial Renewables to be flattish through 2024, in line with DUK's guidance.

## ESG

DUK plans to hold an ESG investor day on 5/20/20 in Charlotte. In our investor polls, DUK tends to be voted the worst utility on ESG; we suspect much of the sentiment is tied to the 2014 Dan River coal ash incident. But on the 4Q19 earnings call, DUK made its case briefly, noting among other things that it announced 1,500 MW of new wind/solar projects in 2019 and had the third best Bloomberg ESG score among US utilities. We expect much more in May. Meanwhile, DUK's coal rate base, when excluding dual coal/gas units and IGCCs, is about 9% of total rate base, which is in line with the utility average (for more, see our recent ESG-related coal exposure report).

**Exhibit 5: DUK Relative Performance vs. Regulated Utilities**




Source: Wolfe Utilities & Power Research, FactSet

## Regulated comps table

### Exhibit 6: Regulated comps

| Company Name | Ticker | Current Price | Current Shares | Mkt Cap ($M) | P/E 2019E | P/E 2020E | P/E 2021E | P/E 2022E | Div Yield | Div Growth (E) | Payout Ratio | Price/ Book | Equity Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Alliant Energy | LNT | $59.38 | 244 | $14,493 | 25.8x | 24.7x | 23.3x | 22.1x | 2.6% | 6.0% | 63% | 2.9x | 45% |
| Ameren | AEE | 85.75 | 246 | 21,097 | 26.4x | 24.8x | 23.0x | 21.7x | 2.3% | 4.0% | 57% | 2.6x | 46% |
| American Electric | AEP | 102.85 | 494 | 50,803 | 24.5x | 23.3x | 22.0x | 20.7x | 2.7% | 6.0% | 63% | 2.6x | 43% |
| Avangrid | AGR | 53.58 | 309 | 16,557 | 23.7x | 21.5x | 19.9x | 18.5x | 3.3% | 2.5% | 70% | 1.1x | 71% |
| CMS Energy | CMS | 67.92 | 284 | 19,281 | 27.1x | 25.4x | 23.8x | 22.1x | 2.4% | 7.0% | 61% | 3.8x | 28% |
| Con Edison | ED | 93.64 | 332 | 31,129 | 21.7x | 20.7x | 19.9x | 19.1x | 3.3% | 3.5% | 68% | 1.7x | 45% |
| **Duke Energy** | **DUK** | **100.11** | **733** | **73,381** | **19.8x** | **19.3x** | **18.3x** | **17.6x** | **3.8%** | **2.5%** | **73%** | **1.6x** | **43%** |
| Edison International | EIX | 77.37 | 359 | 27,745 | 16.1x | 17.5x | 16.4x | 15.4x | 3.3% | 3.0% | 58% | 2.1x | 45% |
| Entergy | ETR | 133.25 | 199 | 26,517 | 24.9x | 23.8x | 22.4x | 21.2x | 1.4% | 3.0% | 32% | 6.8x | 34% |
| Evergy | EVRG | 71.55 | 228 | 16,306 | 25.2x | 23.0x | 21.9x | 21.1x | 2.8% | 6.0% | 65% | 1.9x | 54% |
| Eversource Energy | ES | 92.48 | 324 | 29,941 | 26.8x | 25.2x | 24.0x | 22.7x | 2.5% | 6.0% | 62% | 2.5x | 45% |
| FirstEnergy | FE | 51.95 | 541 | 28,105 | 20.4x | 20.9x | 19.7x | 18.9x | 3.0% | 6.0% | 63% | 2.1x | 43% |
| Fortis* | FTS | 58.37 | 458 | 26,733 | 23.0x | 22.4x | 20.6x | 19.4x | 1.9% | 6.0% | 41% | NA | 59% |
| NiSource | NI | 30.19 | 374 | 11,277 | 23.4x | 22.0x | 20.8x | 19.5x | 2.8% | 2.5% | 61% | 1.9x | 40% |
| PG&E | PCG | 16.76 | 529 | 8,870 | 4.4x | 7.9x | 12.0x | 11.1x | 0.0% | 0.0% | 0% | 1.0x | 37% |
| Pinnacle West | PNW | 100.22 | 112 | 11,266 | 21.4x | 20.5x | 19.4x | 18.5x | 3.1% | 6.0% | 64% | 2.0x | 51% |
| Portland General | POR | 62.34 | 89 | 5,571 | 26.1x | 24.1x | 22.5x | 21.7x | 2.5% | 6.5% | 59% | 2.2x | 50% |
| PPL Corp. | PPL | 36.28 | 723 | 26,232 | 15.0x | 14.2x | 14.6x | N/A | 4.5% | 1.5% | 65% | 2.2x | 35% |
| Southern Company | SO | 69.54 | 1,049 | 72,929 | 22.3x | 21.8x | 20.9x | 19.4x | 3.6% | 3.5% | 78% | 2.7x | 39% |
| WEC Energy Group | WEC | 101.21 | 315 | 31,925 | 28.7x | 27.1x | 25.4x | 23.8x | 2.5% | 7.0% | 68% | 3.2x | 45% |
| Xcel Energy | XEL | 69.82 | 524 | 36,613 | 26.5x | 25.2x | 23.6x | 22.2x | 2.3% | 6.0% | 58% | 2.8x | 41% |
| | | | | | | | | | | | | | |
| **Average** | | | | | **22.5x** | **21.7x** | **20.7x** | **19.8x** | **2.7%** | **4.5%** | **59%** | **2.5x** | **45%** |
| **Average (ex EIX, PCG, PPL)** | | | | | **24.3x** | **23.1x** | **21.7x** | **20.6x** | **2.7%** | **5.0%** | **62%** | **2.6x** | **46%** |

Source: Wolfe Research

**February 13, 2020**

## DISCLOSURE SECTION

**Analyst Certification:**

The analyst of Wolfe Research, LLC primarily responsible for this research report whose name appears first on the front page of this research report hereby certifies that (i) the recommendations and opinions expressed in this research report accurately reflect the research analysts' personal views about the subject securities or issuers and (ii) no part of the research analysts' compensation was, is or will be directly or indirectly related to the specific recommendations or views contained in this report.

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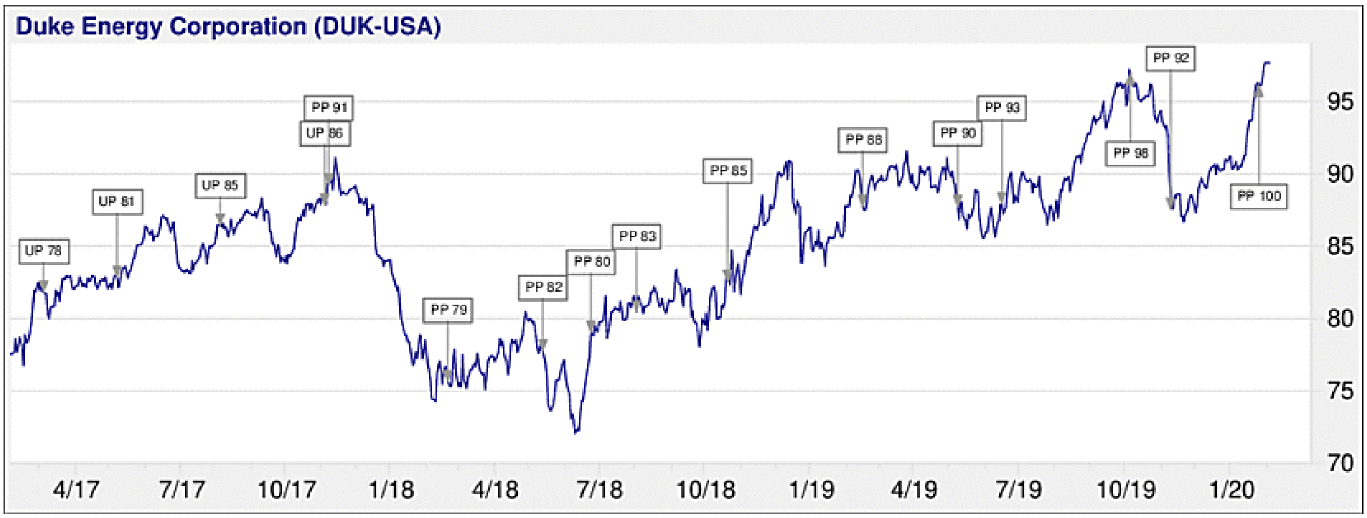
Price Chart with Ratings and Target Price History




Note: OP = Outperform; PP = Peer Perform; UP = Underperform

**Wolfe Research, LLC Fundamental Valuation Methodology:**

| Company: | Fundamental Valuation Methodology: |
|---|---|
| DUK US Equity | P/E |

**Wolfe Research, LLC Fundamental Recommendation, Rating and Target Price Risks:**

| Company: | Risks That May Impede Achievement of the Recommendation, Rating or Target Price: |
|---|---|
| DUK US Equity | Economy, ACP delays and regulatory outcomes |

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| | |
|---|---|
| Outperform (OP): | The security is projected to outperform analyst's industry coverage universe over the next 12 months. |
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| | | |
|---|---|---|
| Outperform: | 46% | 2% Investment Banking Clients |
| Peer Perform: | 43% | 2% Investment Banking Clients |
| Underperform: | 11% | 0% Investment Banking Clients |

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# YOUNG REBUTTAL EXHIBIT NO. 7

**From:** Steve Fleishman
**To:** Stewart, Daniel
**Subject:** The Fleishman Daily 2/25/20 - D/DUK, D, EXC, CNP, Moody's, Weekly Mark, LNG, OKE, ETRN, Midstream
**Date:** Tuesday, February 25, 2020 9:04:11 AM



# The Fleishman Daily 2/25/20

## Utilities: D/DUK, D, EXC, CNP, Moody's, Weekly Mark

## Midstream: LNG, OKE, ETRN, Midstream

### Utilities

**D/DUK** – Supreme Court seems to lean toward a favorable outcome for ACP; positive but expected
**D** – Clean Economy Act, offshore wind standalone both pass out of VA Senate committee; bill aimed at altering GTSA yet to be considered
**DUK/D** – NCUC's final order in D's NC rate case largely unchanged from recent notice; read-through to DUK
**EXC** – meeting with management – IL clean air law slowly progressing
**CPN** – Year-end results show record high EBITDA and FCF on strong ERCOT performance
**Utilities & Midstream** – A Moody's lifter
**The Weekly Mark** – Down Elon's rabbit hole

### Midstream

**LNG** – Q4 beats, 2020 guidance reaffirmed despite low global prices on hedges; room on repurchase; positive messaging
**OKE** – 2020 guidance in line but 2021 initial look better than expected, $920M of growth projects announced; positive
**ETRN** – What's good for ACP is good for MVP
**Midstream** – Big insider buying continues; ET/PAGP/EPD

**Quarterly data: Weather, Forward Prices, Spot Prices, Nuke Outages**

**Wolfe Utility & Midstream Materials: Utility Comps, Utility Stock Charts, Midstream Comps, Midstream Stock Charts, Valuation Charts, Models, Arb Spreads**

# Utilities

D/DUK – Supreme Court seems to lean toward a favorable outcome for ACP; positive but expected

- Yesterday, the SCOTUS heard oral arguments in ACP's Cowpasture case, where the VA 4th Circuit Court of Appeals held that ACP cannot cross the Appalachian Trail in a national forest
- After reading the transcript and media reports, it sounded that four of the conservative justices (Roberts/Gorsuch/Kavanaugh/Alito) interpreted statutes at issue favorably for ACP (Thomas remained silent)
    - Chief Justice Roberts asked about practical implications of the case for energy development, asking if the 4th Circuit's ruling would erect an "impermeable barrier"
    - Justice Alito asked "instead of having to draw this distinction between the trail and the land, why can't we just say that the trail is on the surface and something that happens 600 feet below the surface is not the trail?"
- More importantly, some Democrat appointees (Breyer/Sotomayor/Kagan) also seemed skeptical of the Respondent's arguments
    - Justice Breyer joined in on Justice Alito's line of questioning and wasn't sure whether the Nat'l Park Service or Forest Service had real control over the land
    - Justice Sotomayor joined in on Chief Justice Robert's question about practical implications and went further as to ask why the "parade of horribles" was unlikely
    - Justice Kagan added that "nobody makes that distinction in real life" when referring to the Respondent's argument that a trail was distinct from land
- A final decision from the SCOTUS is expected in May or June

We were happy to see a positive reaction to the Supreme Court arguments for both D and DUK yesterday. That said, we had expected that ACP would be successful on the Appalachian Trail issue once the Supreme Court took the case last fall. An interesting wrinkle is the level of skepticism from Democrat appointees over the Respondent's arguments, suggesting that ACP could win the case in a 6-3 or 7-2 vote vs a party-line vote. We would expect that the Supreme Court's ruling is explicit in reversing the 4th Circuit's decision rather than simply remanding it back to the 4th Circuit. A conclusive ruling from the SCOTUS could potentially have an impact on the 4th Circuit's subsequent views on ACP-related issues (i.e., the biological opinion) which would be helpful. We believe the critical path issue for ACP remains getting the biological opinion through the 4th Circuit.

D – Clean Economy Act, offshore wind standalone both pass out of VA Senate committee; bill aimed at altering GTSA yet to be considered

- Yesterday, the VA Senate Commerce and Labor Committee reported the VA Clean Economy Act (HB 1526) and an offshore wind standalone (HB 1664) by an 11-3 and 12-3 vote, respectfully
    - Both bills have companion bills that crossed over into the House and are currently before the Commerce and Labor Committee
- HB 1526 is a comprehensive piece of legislation which covers a wide range of clean energy initiatives in the state (including offshore wind)
- HB 1664 includes the same provisions for offshore wind as HB 1526 but is narrow in scope and specific to offshore wind (5,200 MW by 2034; 2,500-3,000 MW by 2026 developed by D)

- HB 1132, the Fair Energy Bills Act, which aimed to alter the GTSA to the detriment of D was not taken up for consideration yesterday
- The House Commerce and Labor Committee are scheduled to meet this afternoon; VA's legislative session adjourns on March 7th

It is good to see bills that would enable D's offshore wind plans move one step closer to passing in the Senate (already have in the House). Further, support from the Commerce and Labor Committee was conclusive which bodes well for a full Senate vote. Importantly, the Fair Energy Bills Act, which is anti-D legislation was not docketed for consideration, suggesting that the Senate may have chosen to kill it. It appears that the legislative session is proving out to be constructive for Dominion.

<u>DUK/D – NCUC's final order in D's NC rate case largely unchanged from recent notice; read-through to DUK</u>

- This week, the NCUC issued a final order in Dominion's NC rate case, after issuing a Notice of Decision with highlights of its order last month.
- The final order maintained the settled ROE of 9.75% and equity ratio of 52%; the NCUC wrote the ROE is "equal to the lowest…granted by the Commission for a major electric utility in the last ten years."
    - DUK's DEP/DEC are allowed 9.9% and 52%; in their pending rate cases, they have requested 10.3% ROE and 53% equity ratio.
    - Public Staff last week recommended for DEC's pending rate case a 9.0% ROE and 50% equity ratio.
- The final order also set terms of coal ash cost recovery, which appear unchanged from the Notice last month:
    - Full recovery of past costs – consistent with the previous orders for DUK's DEC/DEP;
    - Coal ash costs will be excluded from rate base and recovered over a 10-year amortization period – <u>differs</u> from the 5-year period in the DEC/DEP orders;
    - During the amortization and 10-year recovery period, coal ash costs shall not earn a return – <u>differs</u> from that allowed in the DEC/DEP orders.
- In the pending rate cases for DEC and DEP, both have requested deferral of costs over 5 years ($480M for DEC, $530M for DEP) and continued deferral of ongoing coal ash costs with a full return.
- Last week, Staff recommended 50/50 sharing of costs (as they did in the 2017/18 rate cases) in the DEC rate case; NCUC will hold hearings beginning 3/23, with rates effective by Aug; intervenor testimony in DUK's DEP rate case is set for 3/25, with hearings beginning 5/4 and rate effective by Sep.

The NCUC's decision that coal ash costs shall not earn a return during the coal ash cost recovery period is a bothersome data point for DUK. Even Moody's suggested yesterday that would be a negative development for NC regulation. The 10-year recovery period also could impact cash vs the 5-year period awarded DUK last time. Still, the 9.75% ROE and 52% equity ratio were both decent data points for DUK, given the low interest and high utility valuation environment. The NC rate cases, and to a lesser extent the IN rate case, are key events for DUK stock.

EXC – meeting with management – IL clean air law slowly progressing

- We met with EXC management yesterday for a brief update. There was nothing new to report on IL investigations, but it was nice to see that Clean Air legislation is progressing.
- The first legislative hearing on the Clean Air Clean Jobs Act was held last week in IL and the company thought the hearing was effective in highlighting the benefits of the law including environmental and job benefits.
- Nothing gets done in IL until around the session end so we still expect the bill to come to a head in late May.
- EXC's utilities continue to perform very well. Multi-year rate plans are possible in MD and DC later this year for the first time.
- We were better able to tie down the differential between EXC's capex increase on the YE call and ratebase staying about the same. Starting ratebase came down about $400M and CWIP for some larger transmission projects is a bigger piece of the mix during the forecast period.
- Overall, we continue to view EXC as an attractive de-risking play on the potential for L-T visibility for the IL nuclear fleet that is getting little to no credit in the current stock price.

CPN – Year-end results show record high EBITDA and FCF on strong ERCOT performance

- This morning, Calpine (formerly CPN, now private) reported year-end results – adjusted Free Cash Flow of $1,133M (vs. $976M in 2019) and adjusted EBITDA of $2,291M (vs. $2,077M last year)
  - Results were driven by improved commodity margin in the West and Texas regions, along with better retail performance; offset by weaker commodity margin in the East
    - West – higher resource adequacy revenues and hedging contribution, partially offset by lower RMR revenue and lower generation at Geysers geothermal plant due to wildfire outage
    - Texas – strong spark spreads in August/September – up $211M YoY
    - Retail – stronger gas supply hedging and lower costs
    - East – lower capacity revenues in PJM/NE and sale of Garrison/RockGen plants
- Capital allocation – after paying special dividends of $400M and $750M in 2019 to its parent entity, CPN finished the year with $1.5B of cash equivalents on its balance sheet
- Both of these results were the highest we've ever seen for Calpine in as long as we can remember – the company typically posted EBITDA in the $1.8-2.0B range and FCF in the $600-800M range, up until last year's impressive results

At a high level, the results signal continued strong financial metrics. It's good to be Calpine and it's good to be private in the power sector right now. Hopefully the positive result has a read-through to the publicly-traded IPPs reporting later this week, which have been unable to catch a bid in recent months.

Utilities & Midstream – A Moody's lifter
**Click here to view our complete note**
**Utilities: 2020 is a year of stabilization**

We hosted our annual investor meeting with the Moody's team to get their latest credit views on the utilities, power and midstream sectors. The outlook for utilities is improving. Only 12% of ratings have a negative outlook today (SRE, AEP, PNW, ED, and AES' DPL) down from 31% post tax reform. Outside of few states (Maine, Texas, Arizona), regulation has been constructive. That said, many companies still operate with little cushion in their metrics and some are slightly below their rating thresholds (SRE, D). ESG has a heightened focus at Moody's but is not a key driver of credit actions at this point. Key credits we discussed included CNP, AEP, D, DUK, SRE, NEE and of course PCG – see more in full report.

The Weekly Mark – Down Elon's rabbit hole

**Click here to view our complete note**

**What's the EV opportunity for utilities?** ESG and energy transition has been a big investor focus over the past few months. Electric utilities could have a key role to play in renewable generation construction given attractive economics of wind/solar/storage and significant upside in electricity demand from electric vehicles. The first driver is well underway as renewables are dominating new capacity additions. On the second, EV adoption is steady to date, but what if, in the spirit of the UK's recent announcement to ban gasoline car sales by 2035, all U.S. cars were swapped EVs? Stay with us here. Clearly this isn't happening anytime soon but even if only a fraction of EV conversion happens it could represent a huge amount of new generation capacity needs plus the need for significant T&D infrastructure upgrades.

## Midstream

LNG – Q4 beats, 2020 guidance reaffirmed despite low global prices on hedges; room on repurchase; positive messaging

- Cheniere reported Q4 EBITDA of $987M vs. $634M in 2018, significantly above our $909M estimate and the $940M consensus
- EBITDA rose on a 62% increase in LNG volumes from the additional trains in service, partially offset by higher operating costs
- Reiterated 2020 guidance. Cheniere reiterated 2020 EBITDA of $3.8B-$4.1B and DCF of $1B-$1.3B despite the weak global LNG market environment
    - 95% of 2020 production has been sold forward; $1 change in market margin impacts EBITDA by $80M (down from $100M in Q3)
- $750M buyback room left. As of yearend 2019, Cheniere had repurchased about 4M shares under its $1B authorization, leaving about $750M left for future repurchases
    - Cheniere also announced a transaction to redeem $300M of converts held by EIG for cash; prevented 6M shares of LNG getting issued
- Corpus 3, Sabine 6 on schedule. Corpus Christi 3 remains on schedule for 1H-2021 completion and Sabine Pass 6 is on target for 1H-2023 completion

There were a series of positives in the release: a Q4 beat, maintained guidance despite weak global LNG prices, reduced exposure to the open market, significant buyback capacity and work to reduce dilution from the converts. With long-term contracts kicking in at Corpus 2 in the next couple months Cheniere's exposure to the market will step down again as well. Apart from that, operations continue to be good and we liked that it is working to manage the converts with excess cash while still having a lot of room left on the buyback. The main questions will be on the conditions of the current spot market and when is that expected to normalize, as well as a better sense of a reasonable timeline on commercialization of Corpus midscale.

OKE – 2020 guidance in line but 2021 initial look better than expected, $920M of growth projects announced; positive

- ONEOK reported Q4 EBITDA of $661M vs. $625M in 2018, a little below our $673M estimate and the $680M street. Growth was driven by a combination of higher volumes in the NGL pipelines from Elk Creek and Arbuckle II and higher G&P volumes in the Williston offset by lower volumes in the Mid-Con.
- **2020 guidance detailed; in line**. OKE initiated 2020 EBITDA guidance of $3.1B-$3.35B, about in line with the street. Total capex was $2.45B-$2.95B, above WR estimate of $2.5B
- **2021 growth of 20% is better than consensus**. OKE indicated that 2021 EBITDA would be about 20% above the 2020 midpoint, or about $3.85B. This is well above consensus of $3.6B and above WR at $3.7B
- **Another $920M of growth projects announced**. OKE put the entire Elk Creek pipeline into service in December and now announced an expansion to 400 kbpd at a cost of $305M, up from 240 kbpd current capacity. OKE also announced a $310M, 100 kbpd expansion of West Texas LPG and a $305M, 200 mmcf/d expansion of Demicks Lake. The NGL expansions are expected return <4x EBITDA and Demicks a 4-5x multiple.

The report and guidance is positive and the company continues to demonstrate why it trades at a premium. The 2021 growth potential of 20% is better than our 15% estimate and even better than the street. The expansion of Elk Creek, West Texas LPG and Demicks Lake processing should continue that momentum into 2022 and we note that OKE remains one of the few companies in the sector with enough credibility that growth announcements are actually well-received. If we had to nitpick, the less good parts of the report were capex and EBITDA segment mix. 2020 capex at the midpoint is about $250M above our estimate, but likely attributable to the new growth projects. Additionally, the 2020 segment EBITDA was higher on G&P and lower on the NGL and natural gas pipeline segments than we had in our numbers – G&P fits into our valuation framework as a discount to the pipeline assets. Despite this, still a good report and we expect the stock to outperform today.

ETRN – What's good for ACP is good for MVP
**Click here to view our complete note**
**Supreme Court seems to side with Atlantic Coast Pipeline.** Shares of ETRN outperformed the AMZ by 500 bp on Monday after the Supreme Court heard US Forest Service v. Cowpasture and appeared to lean in favor of allowing ACP to cross the Appalachian Trail (ANST). See our preview published over the weekend for background (link). Several justices, including some Dem. appointees, struggled with the lower court's decision. We had expected the court to be skeptical of the case and there seems to be a path forward for ACP and ETRN's Mountain Valley Pipeline. We continue to believe MVP is likely to be completed and we remain Outperform on ETRN/EQM.

Midstream – Big insider buying continues; ET/PAGP/EPD

- There was more significant insider buying after the close yesterday in the sector:

**A form 4 after the close yesterday shows that ET CEO Kelcy Warren bought $45M of ET stock through a DRIP.** Warren receives distributions of about $78M/quarter, implying that he reinvested about 60% of his quarterly distribution back into the stock. This marks the 4th straight quarter where Warren has repurchased significant stock through the DRIP.

- **PAGP's director and former CEO Greg Armstrong bought $1.1M of stock** yesterday in the open market.
- **Lastly, EPD's Chairman Randa Duncan Williams bought her now typical 50,000 units again yesterday ($1.25M).** Duncan Williams has generally bought 50,000 units in the market every single day since EPD reported earnings in late January and the quiet period presumably ended.

There continues to be large insider buying activity in the midstream space despite poor stock performance.

## Wolfe Events

March 2: CNP non-deal roadshow in NYC
March 6: AES Fireside Chat with CEO Andres Gluski
March 9: Lunch with Sustainalytics in NYC
March 12-13: CMS non-deal roadshow in LA/SF
March 19: DTE Fireside Chat with CEO Jerry Norcia
March 25: EIX non-deal roadshows in Irwindale, CA
March 26: PCG non-deal roadshows in San Francisco
March 30: Houston bus tour with LNG, PAA, TRGP, ENB, CNP, NRG, and VST
April 2: WEC non-deal roadshow in Chicago
April 2-3: ES non-deal roadshow in Europe
May 13-14: NEE non-deal roadshow in Boston/NY
June 17-18: CNP non-deal roadshow in Sydney
August 25-26: DTE non-deal roadshow in Sydney
September 7-9: AWK non-deal roadshow in Sydney
September 30-October 1: Wolfe Utilities & Energy Conference in NYC
October 2: AEE non-deal roadshow in Boston

## Most Popular Reports

**Utilities Top 10 for 2020**
**Midstream Top 10 for 2020**
**Midstream SOTP Valuation Methodology**
**Utilities Credit Metrics Outlook**
**Midstream Credit Metrics Outlook**
**Power Supply Outlook**
**Utility Proxy Review**
**Midstream Proxy Review**
**Utility Pension Review**
**Wolfe Utility Primer**

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# YOUNG REBUTTAL EXHIBIT NO. 8

BARCLAYS

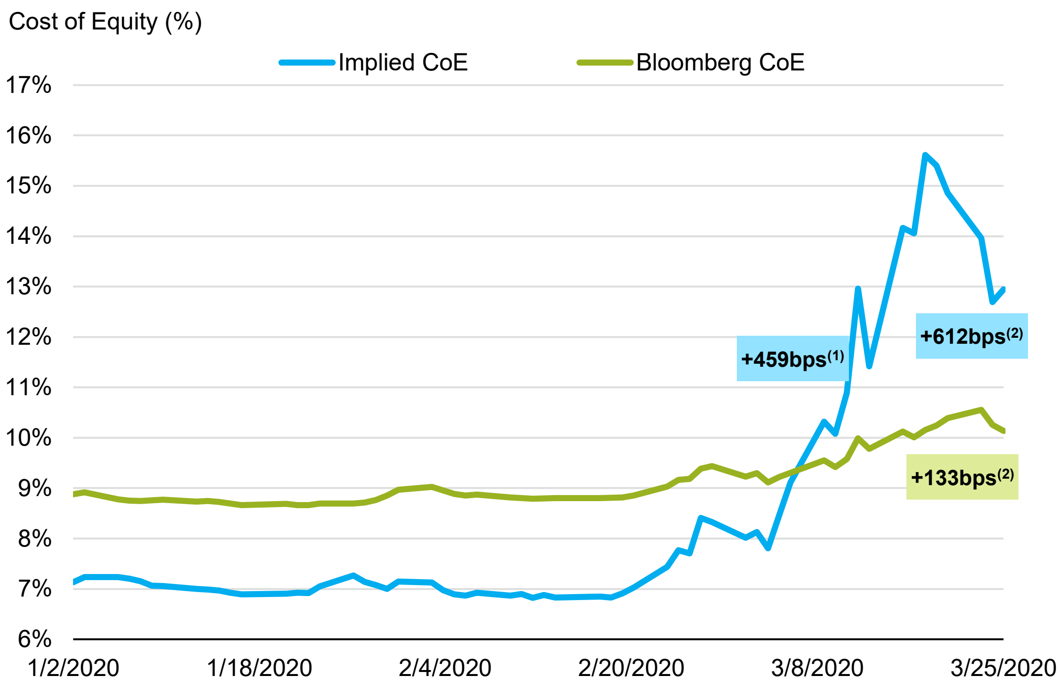
# Cost of Equity Analysis

March 28, 2020

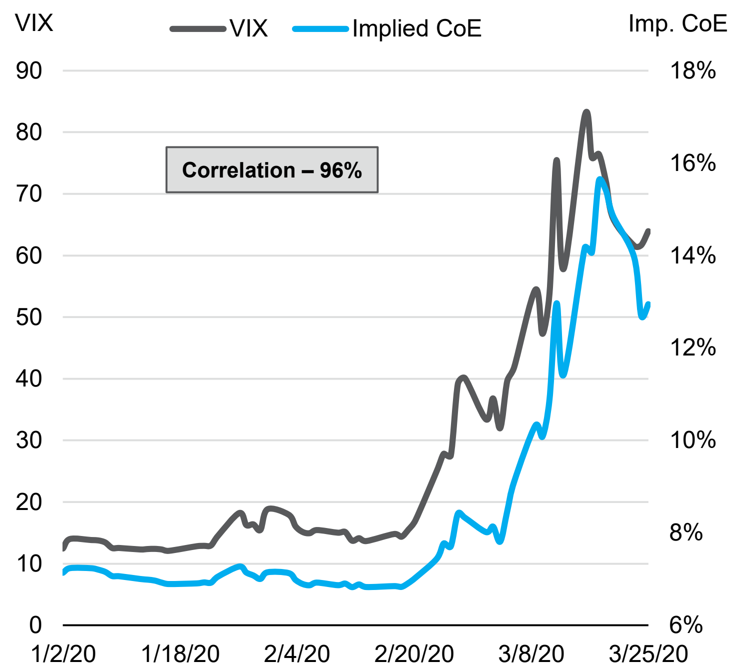
# S&P 500 Cost of Equity Has Increased 100-400+ bps

**Forward-looking methods of calculating Cost of Equity may be preferable to use in market dislocations as they tend to capture the prevailing market risk better**

## S&P 500 Implied and Bloomberg Costs of Equity, YTD




## VIX Index and S&P 500 Implied CoE, YTD




## Commentary

- Forward-looking Cost of Equity metrics have increased, in some cases significantly, since end of February (February 19th)
  - Bloomberg Estimate increase of ~100bps using proprietary long-term methodology
  - Market Implied CoE approach suggests ~400-500bps of increase over short / medium term
- Market Implied approach moving in lock-step with VIX

1. *Changes measured from 2/19/2020 to 3/13/2020.*
2. *Changes measured from 2/19/2020 to 3/25/2020.*

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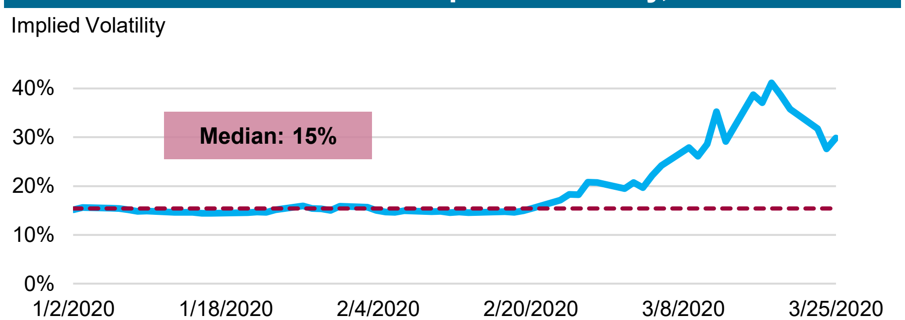
# S&P 500 Current Forward Looking Cost of Equity Estimate

## Overview of Implied COE Methodology

- For any company, the cost of equity must be greater than the cost of debt, due to its subordination in the capital structure
  - **Cost of Equity > Cost of Debt**
- Cost of Debt is readily observed in the market
  - **Cost of Debt = Risk Free Rate + Credit Spread**
- To determine the excess return required by investors to hold equity instead of debt, we calculate the cost of a put option that protects against realizing a lower expected return
  - **Cost of Equity = Cost of Debt + Excess Required Return**
- Excess Required Return can be derived from traded options and calculated in 4 steps:
  1. Calculation of forward breakeven stock price
  2. Estimation of future stock volatility
  3. Calculation of cost of downside insurance in $
  4. Translation into annualized "excess equity return"

## S&P 500 1-Year Implied Volatility, YTD




## 2-Year Implied Cost of Equity: S&P 500 (Mar 25th, 2020)

| | | |
|---|---|---|
| | Current Stock Price | $2,475.56 |
| | Annual Dividend | $60.45 |
| | Dividend Yield ($R_{div}$) | 2.44% |
| | Cost of Debt ($R_{debt}$)[(1)] | 4.46% |
| | Min Capital Gain ($R_{debt}$ - $R_{div}$) | 2.02% |
| 1 | Forward Stock Price | $2,576.48 |
| 2 | Implied Volatility | **29.9%** |
| 3 | Put Struck at Forward Price | $393.56 |
| 4 | Annuitized Put Price ($R_{put}$) | 8.5% |
| | **2-Year Implied Cost of Equity** | **12.9%** |
| | **CAPM Cost of Equity**[(2)] | **8.4%** |
| | Bloomberg Cost of Equity | 10.1% |

+

1. *Cost of debt for S&P assumed to be Treasury + BBB credit spread.*
2. *CAPM cost of equity calculated as 20-year US Treasury yield (1.23%) + S&P 500 beta (1.00) * equity market risk premium (7.15%).*

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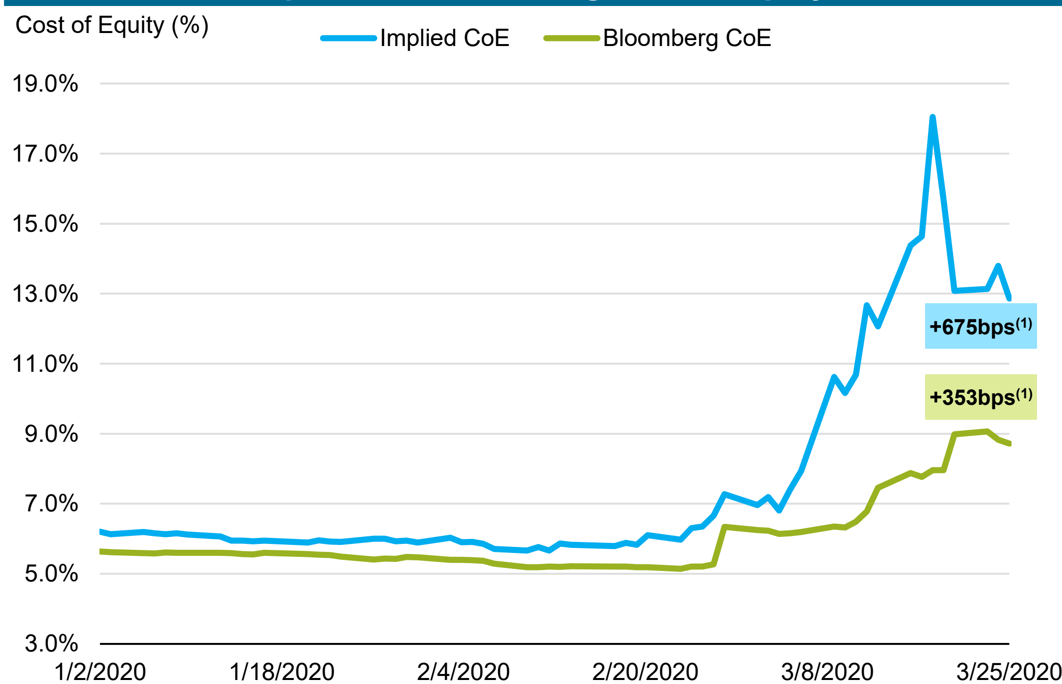
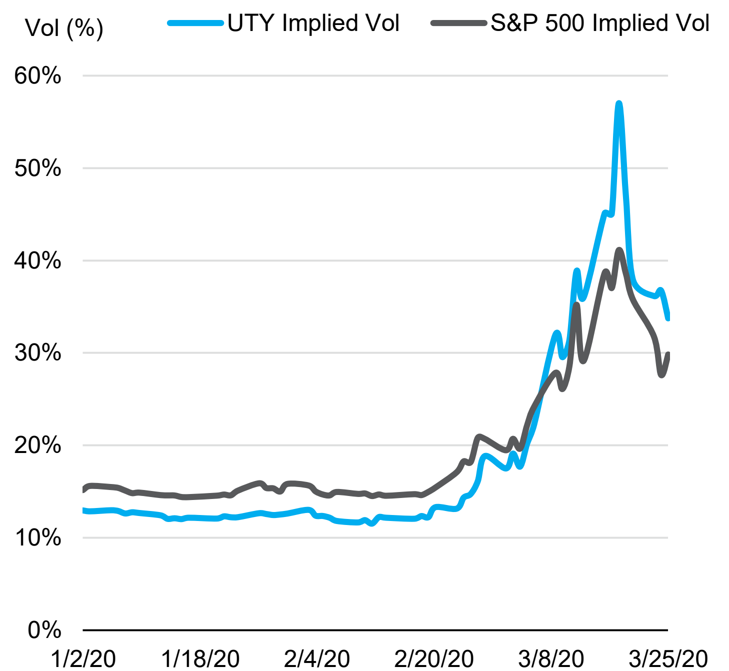
# UTY Cost of Equity Has Increased 300-600+ bps

**Forward-looking methods of calculating Cost of Equity may be preferable to use in market dislocations as they tend to capture the prevailing market risk better**

## UTY Implied and Bloomberg Cost of Equity, YTD




## S&P 500 and UTY Option Implied Vol, YTD




## Commentary

- Forward-looking Cost of Equity metrics have increased significantly, since end of February (February 21st)
  - Market Implied CoE approach suggests ~675bps of increase over short / medium term
  - Bloomberg Estimate increase of ~350bps using proprietary long-term methodology
- UTY index volatility has spiked higher than the S&P 500 index volatility

*Note: Bloomberg CoE calculated as 10-year US Treasury yield (0.87%) + UTY 2Y Adjusted Weekly beta (0.85) * Bloomberg country risk premium (9.27%).*
*1. Changes measured from 2/21/2020 to 3/25/2020.*

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# UTY Current Forward Looking Cost of Equity Estimate

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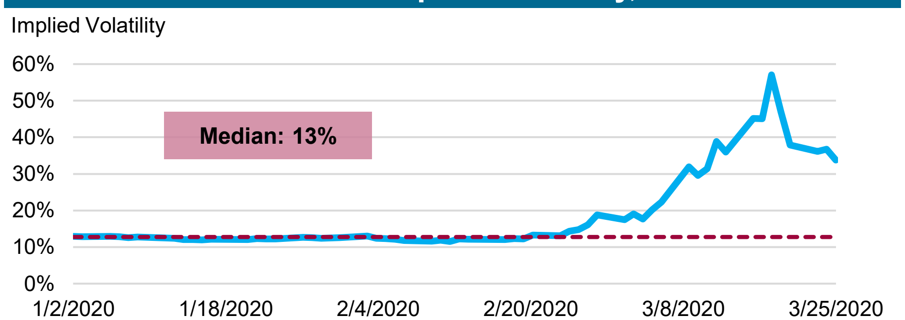
  3. Calculation of cost of downside insurance in $
  4. Translation into annualized "excess equity return"

## UTY 1 -Year Implied Volatility, YTD




## 2-Year Implied Cost of Equity: UTY (Mar 25th, 2020)

| | | |
|---|---|---|
| | Current Stock Price | $659.96 |
| | Annual Dividend | $25.98 |
| | Dividend Yield ($R_{div}$) | 3.94% |
| | Cost of Debt ($R_{debt}$)(1) | 3.66% |
| | Min Capital Gain ($R_{debt}$ - $R_{div}$) | (0.27%) |
| 1 | Forward Stock Price | $656.37 |
| 2 | Implied Volatility | **33.7%** |
| 3 | Put Struck at Forward Price | $115.02 |
| 4 | Annuitized Put Price ($R_{put}$) | 9.2% |
| | **2-Year Implied Cost of Equity** | **12.9%** |
| | **CAPM Cost of Equity(2)** | **7.3%** |
| | Bloomberg Cost of Equity(3) | 8.7% |

+

1. *Cost of debt for UTY assumed to be Treasury + Utility BBB credit spread.*
2. *CAPM cost of equity calculated as 20-year US Treasury yield (1.23%) + UTY 2Y Adjusted Weekly beta (0.85) * equity market risk premium (7.15%).*
3. *Bloomberg CoE calculated as 10-year US Treasury yield (0.87%) + UTY 2Y Adjusted Weekly beta (0.85) * Bloomberg country risk premium (9.27%).*

BARCLAYS

INFORMATION SHEET

PRESIDING: Commissioner Clodfelter, Presiding; Chair Mitchell; and Commissioners Brown-Bland, Gray, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Tuesday, September 29, 2020
TIME: 9:00 a.m. – 12:30 p.m.
DOCKET NOS.: E-2, Sub 1219 and E-2, Sub 1193
COMPANY: Duke Energy Carolinas, LLC; Duke Energy Progress, LLC
DESCRIPTION: E-2, Sub 1219, In the Matter of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-2, Sub 1193, Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 11

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

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COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
**CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED**: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Schauer, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, Luhr and Coxton

REPORTED BY: Kim Mitchell
TRANSCRIBED BY: Kim Mitchell
DATE FILED: October 6, 2020

TRANSCRIPT PAGES: 183
PREFILED PAGES: 1151
TOTAL PAGES: 1334

PLACE: Held via Videoconference

DATE: Tuesday, September 29, 2020

TIME: 9:00 a.m. - 12:30 p.m.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 11

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T A B L E  O F  C O N T E N T S

E X A M I N A T I O N S

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd

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E X H I B I T S

E X H I B I T S (Cont'd.)

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T A B L E   O F   C O N T E N T S

E X A M I N A T I O N S

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd

E X A M I N A T I O N S Cont'd



E X H I B I T S

# E X H I B I T S (Cont'd.)

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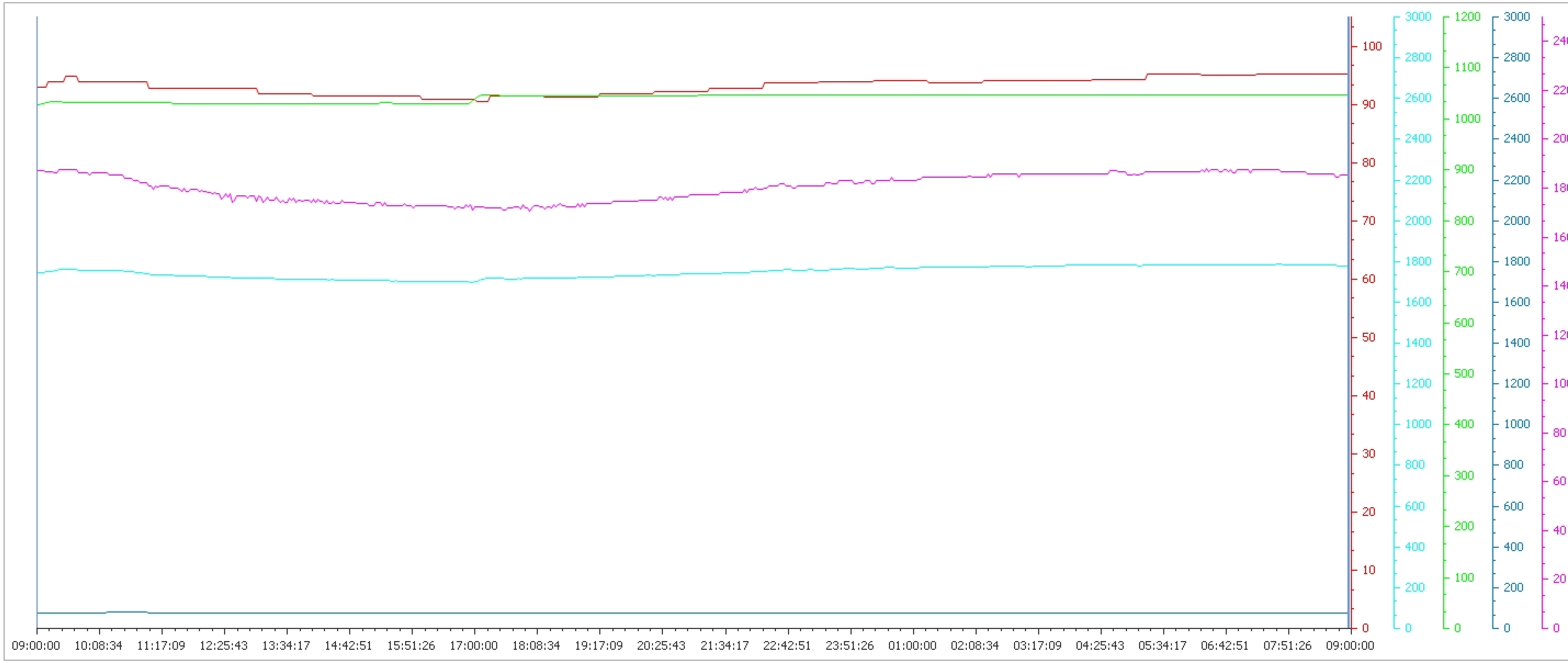
I/A

Start Time : 04/04/2020 09:00:00 L1 : 04/04/2020 09:00:00
End Time : 04/05/2020 09:00:00 L2 : 04/05/2020 08:57:36, (L2 - L1) : 23:57:36

| | G | Point Name | Historian | Process | Description | End Value | Units | S | Low Scale | High Scale | Left Curso | Right Curs | Differe |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ☑ | (A) 08STDWATT.UNIT78@NET2 | Auto Historian | Actual | GENERATOR WATTS | 95.3 | MW | ☑ | 0 | 105 | 92.9 | 95.3 | 2.4 |
| | ☑ | (A) 08STIP_P.UNIT78@NET2 | Auto Historian | Actual | INLET PRESS FEEDBACK | 1777.00 | PSIG | ☑ | 0 | 3000 | 1744.91 | 1777.00 | 32.09 |
| | ☑ | (A) 08STTT_RHS.UNIT78@NET2 | Auto Historian | Actual | REHEAT STEAM TEMP | 1047.4 | DEGF | ☑ | 0 | 1200 | 1028.4 | 1047.4 | 19.0 |
| | ☑ | (A) 08STAP_P.UNIT78@NET2 | Auto Historian | Actual | 0 | 77.1 | PSIG | ☑ | 0 | 3000 | 77.1 | 77.1 | 0.1 |
| | ☑ | (A) 07GTJX0008.UNIT78@NET2 | Auto Historian | Actual | 7 GT MW | 185.4 | MW | ☑ | 0 | 250 | 187.0 | 185.4 | -1.6 |



EISENSTEIN MALANCHUK LLP

September 7, 2011

BY FEDERAL EXPRESS

Kenneth Ryan, Esq.
Wiley Rein LLP
1776 K Street, N.W.
Washington, D.C. 20006

Re: Carolina Power & Light/AEGIS – ash pond issues

Dear Ken:

Following up our recent meeting, I am writing to provide further information to explain why we believe that the ash pond issues relating to Progress Energy are now ripe for resolution, and specifically why action is going to be required in the near-term to remediate ash facilities.

First, let me emphasize that what led Progress Energy to renew discussions on the ash ponds, and to provide an updated notice letter, was the increased, aggressive regulatory oversight by the State of North Carolina. Regardless of when the EPA may act, or what other States may do, North Carolina is taking aggressive action on coal ash facilities, commencing with the boundary well monitoring that was required at the end of 2010. Tab 1 discusses how coal ash is already regulated in North Carolina by NCDEHNR; bullet 4 explains why Progress has installed monitoring wells in North Carolina. In turn, tab 2 describes the Corrective Action process if there are exceedances at the compliance boundaries under the existing North Carolina Administrative Code. While EPA CCR regulations might be more prescriptive about exactly what has to be done, existing North Carolina regulations also raise the potential for the same closure scheme. North Carolina is already actively commencing work on ash pond issues, and as we indicated at the meeting exceedances are already being detected at the relevant Progress Energy ash ponds.

In addition, it should be noted that there is a very active network of non-governmental organizations in North Carolina which is specifically pressing for remedial action on North Carolina ash ponds. This, of itself, creates a significant driver that is even more pressing than the lobbying on the federal side. Thus, for example, tab 3 provides a white paper of various organizations detailing their perception of problems with coal ash regulation in North Carolina. Tab 4 provides just a small sampling of a large number of articles and press releases that recurrently appear in North Carolina, urging action on ash pond facilities in that State. In short,

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there is a significant constituency pressing for action in North Carolina, regardless of what may happen on the federal level.

At the same time, we do not minimize the risks of more rapid action by EPA. I realize you are more skeptical of when EPA action will take place. However let us emphasize that, in addition to the potential issuance of CCR regulations by EPA, there are other important regulatory considerations that must be borne in mind, all pointing toward the demise of coal-fired plants. In addition to the CCR rules under RCRA, there is rulemaking underway in the Clean Air Act (CAA) and the Clean Water Act (CWA). Under the CAA there are two new rules, the Clean Air Transport Rule (CATR) and the Hazardous Air Pollutant (HAP) Maximum Achievable Control Technology (MACT), the HAP MACT. Under the CWA there will be rulemaking for the cooling water intake structure requirements. Taken together, it is anticipated that utilities will be driven to make decisions in the near future on the fate of their coal ash facilities, and indeed Progress Energy has already announced the retirement of four of its coal burning power plants. Tab 5 includes a couple of articles on why regulatory requirements are accelerating coal plant retirements. Given the regulatory situation, the reality is that the wise policy decision is to retire older plants. As these plants are retired, remediation obligations will, of course, come to the fore.

Again, let me emphasize that we do not see the remediation that will be required at ash ponds to be either minimal or far in the horizon. We are interested in discussing a potential settlement of these liabilities at this time, in the interest of having some funding available to assist in remediation efforts, and to wrap up these issues before a potential change in the management at Progress Energy with the upcoming merger. However, to the extent our positions are at odds, we are not interested in a *de minimus* settlement, as we anticipate that, with the passage of time, the threat from these issues will continue to become more real, and indeed more expensive.

I look forward to talking further after you have reviewed this letter and the attached material.

Sincerely,

Laurence J. Eisenstein

Attachments

cc (w/o attachments):
Steven Antunes
Peter Alvey
Charles Madison
John Malanchuk