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INFORMATION SHEET

PRESIDING: Commissioner Duffley, Presiding; Chair Mitchell, and Commissioners Brown-Bland, Clodfelter, Hughes, McKissick, Jr., and Kemerait
PLACE: Raleigh, NC
DATE: Tuesday, September 5, 2023
TIME: 9:34 a.m. to 1:07 p.m.
DOCKET NO.: E-7, Sub 1134 and E-7 Sub 1276
COMPANY: Duke Energy Carolinas, LLC
DESCRIPTION: In the Matter of Duke Energy Carolinas, LLC Application for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County, and for an Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance-Based Regulation

VOLUME NUMBER: 16

APPEARANCES
See attached

WITNESSES
See attached

EXHIBITS

None attached

REPORTED BY: Patricia C. Elliott	TRANSCRIPT PAGES: 176
TRANSCRIBED BY: Patricia C. Elliott	PREFILED PAGES: 248
DATE FILED: September 11, 2023	TOTAL PAGES: 424

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PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, September 5, 2023

TIME: 9:34 a.m. - 1:07 p.m.

DOCKET NO: E-7, Sub 1134 and E-7, Sub 1276

BEFORE: Commissioner Kimberly W. Duffley, Presiding
Chair Charlotte A. Mitchell
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Carolinas, LLC

Application for Approval to Construct a 402 MW Natural Gas-Fired Combustion Turbine Electric Generating Facility in Lincoln County

and

Application for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance-Based Regulation

VOLUME 16

Noteworthy Reporting Services, LLC

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FOR NC WARN:
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A P P E A R A N C E S (Cont d.)

FOR THE USING AND CONSUMING PUBLIC PURSUANT TO N.C.G.S. 62-20 AND ON BEHALF OF THE STATE AND ITS CITIZENS PURSUANT TO N.C.G.S. 114-2(8):

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Derrick C. Mertz, Esq., Special Deputy Attorney General
North Carolina Department of Justice
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

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Robert B. Josey, Esq.
Nadia L. Luhr, Esq.
Anne M. Keyworth, Esq.
William S.F. Freeman, Esq.
William E.H. Creech, Esq.
Thomas Felling, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: JACK E. JIRAK, DEPUTY GENERAL COUNSEL

FIRM NAME: DUKE ENERGY

ADDRESS: 410 S. WILMINGTON ST.

CITY: RALEIGH STATE: NC ZIP CODE: 27602

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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_____ **Yes, I have signed the Confidentiality Agreement.**

Email: JACK.JIRAK@DUKE-ENERGY.COM

SIGNATURE: _____

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 6/21/2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Jason Higginbotham
Associate General Counsel

FIRM NAME: Duke Energy

ADDRESS:

CITY: STATE: ZIP CODE:

APPEARANCE ON BEHALF OF: Duke Energy Carolinas LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

Non-confidential transcripts are located on the Commission's website. To view and/or print transcripts, go to https://www.ncuc.net/, hover over the Dockets tab, select Docket Search, enter the docket number, and click search, select the highlighted docket number and select Documents for a list of all documents filed.

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☑ **Yes, I have signed the Confidentiality Agreement.**

Email: jason.higginbotham@duke-energy.com

SIGNATURE:

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: JAMES H. JEFFRIES IV, PARTNER

FIRM NAME: MCGUIREWOODS LLP

ADDRESS: 201 N. TRYON STREET, SUITE 3000

CITY: CHARLOTTE STATE: NC ZIP CODE: 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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X **Yes, I have signed the Confidentiality Agreement.**

Email: JJEFFRIES@MCGUIREWOODS.COM

SIGNATURE: _____

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/23/2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Andrea R. Kells, Counsel

FIRM NAME: McGuireWoods, LLP

ADDRESS: 501 Fayetteville St. Suite 500

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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X **Yes, I have signed the Confidentiality Agreement.**

Email: akells@mcguirewoods.com

SIGNATURE: Andrea R. Kells Digitally signed by Andrea R. Kells Date: 2023.08.23 09:43:52 -04'00'

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 28, 2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Kristin M. Athens, Esquire

FIRM NAME: McGuireWoods LLP

ADDRESS: 501 Fayetteville St. Suite 500

CITY: Raleigh STATE: NC ZIP CODE: _____

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: x COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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x **Yes, I have signed the Confidentiality Agreement.**

Email: kathens@mcguirewoods.com

SIGNATURE: Kristin M. Athens Digitally signed by Kristin M. Athens Date: 2023.08.22 11:24:07 -04'00'

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 22, 2023 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Brandon F. Marzo, Partner

FIRM NAME: Troutman Pepper Hamilton and Sanders LLP

ADDRESS: 600 Peachtree Street NE, Suite 3000

CITY: Atlanta **STATE:** GA **ZIP CODE:** 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X **COMPLAINANT:** ___ **INTERVENOR:** ___

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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X **Yes, I have signed the Confidentiality Agreement.**

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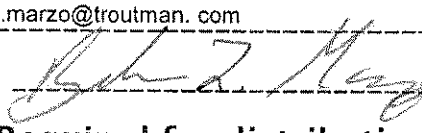
SIGNATURE: 

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/22/23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Melissa Oellerich Butler, Associate

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 600 Peachtreet St. NE Suite 3000

CITY: Atlanta STATE: GA ZIP CODE: 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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X **Yes, I have signed the Confidentiality Agreement.**

Email: melissa.butler2@duke-energy.com

SIGNATURE: Melissa Oellerich Butler Digitally signed by Melissa Oellerich Butler Date: 2023.08.22 09:57:11 -04'00'

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/22/23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Joshua Warren Combs, Associate Attorney

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 600 Peachtree Street, NE, Suite 3000

CITY: Atlanta STATE: GA ZIP CODE: 30308

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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X **Yes, I have signed the Confidentiality Agreement.**

Email: Josh.Combs@troutman.com

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/22/2023 DOCKET NO.: E-7, Sub 1276

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CITY: Charlotte STATE: NC ZIP CODE: 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X COMPLAINANT: ___ INTERVENOR: ___

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

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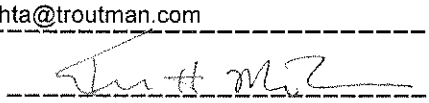
SIGNATURE: 

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 22, 2023 **DOCKET NO.:** Docket No. E-7, Sub 1276

ATTORNEY NAME and TITLE: Molly McIntosh Jagannathan, Partner

FIRM NAME: Troutman Pepper Hamilton Sanders LLP

ADDRESS: 301 South College Street, Suite 3400

CITY: Charlotte **STATE:** NC **ZIP CODE:** 28202

APPEARANCE ON BEHALF OF: Duke Energy Carolinas, LLC

APPLICANT: X **COMPLAINANT:** ___ **INTERVENOR:** ___

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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Digitally signed by Molly M. Jagannathan
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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 23, 2023 **DOCKET NO.:** E-7, SUB 1276

ATTORNEY NAME and TITLE: MELINDA L. MCGRATH, PARTNER

FIRM NAME: TROUTMAN PEPPER HAMILTON SANDERS LLP

ADDRESS: 301 S. COLLEGE STREET; 34TH FLOOR

CITY: CHARLOTTE **STATE:** NC **ZIP CODE:** 28202

APPEARANCE ON BEHALF OF: DUKE ENERGY CAROLINAS, LLC

APPLICANT: XX **COMPLAINANT:** ___ **INTERVENOR:** ___

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

XX **Yes, I have signed the Confidentiality Agreement.**

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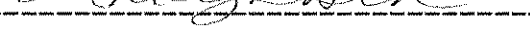
SIGNATURE: 

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Marcus W. Trathen

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 1700 Wells Fargo Capitol Center, 150 Fayetteville St.

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: CUCA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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Email: mtrathen@brookspierce.com

SIGNATURE: /s/ Marcus Trathen

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/23/2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Matthew B. Tynan

FIRM NAME: Brooks Pierce LLP

ADDRESS: P.O. Box 26000

CITY: Greensboro STATE: NC ZIP CODE: 27420

APPEARANCE ON BEHALF OF: Carolina Utility Customers Association

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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x **Yes, I have signed the Confidentiality Agreement.**

Email: mtynan@brookspierce.com

SIGNATURE: Matthew B Tynan

(Signature Required for distribution of CONFIDENTIAL information)

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8-28-23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Christopher B. Dodd

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

ADDRESS: 115 N. 3rd St #301

CITY: Wilmington STATE: NC ZIP CODE: 28401

APPEARANCE ON BEHALF OF: CUCA

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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ONLY fill out this portion if you have signed an NDA to receive CONFIDENTIAL transcripts and/or exhibits:

X **Yes, I have signed the Confidentiality Agreement.**

Email: cdodd@brookspierce.com

SIGNATURE: /s/ Christopher Dodd

(Signature Required for distribution of CONFIDENTIAL information)

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 22, 2023 **DOCKET NO.:** E-7, Sub 1276; E-7, Sub 1134

ATTORNEY NAME and TITLE: Christina Cress, Partner; Douglas "D.C." Conant, Associate (Bailey & Dixon, LLP)

Chris S. Edwards, Partner (Ward & Smith, LLP)

FIRM NAME: Bailey & Dixon, LLP (CDC & DC); Ward & Smith, LLP (CSE)

ADDRESS: 434 Fayetteville St., Ste. 2500 (Bailey & Dixon); 127 Racine Drive (Ward & Smith)

CITY: Raleigh (B&D); Wilmington (W&S) **STATE:** NC **ZIP CODE:** 27601 (B&D); 28403 (W&S)

APPEARANCE ON BEHALF OF: CIGFUR III, Haywood EMC, Blue Ridge EMC, Piedmont EMC, and Rutherford EMC

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** X

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/28/23 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Ethan Blumenthal, Regulatory Counsel

FIRM NAME: North Carolina Sustainable Energy Association

ADDRESS: 4800 Six Forks Rd., Suite 300

CITY: Raleigh STATE: NC ZIP CODE: 27609

APPEARANCE ON BEHALF OF: North Carolina Sustainable Energy Association

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8-28-23 **DOCKET NO.:** G-7, Sub 1276

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CITY: Raleigh **STATE:** NC **ZIP CODE:** 27609

APPEARANCE ON BEHALF OF: NCSEA

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PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/28/23 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Ben Snowden, Partner

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CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: North Carolina League of Municipalities

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PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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APPEARANCE SLIP

DATE: 8/25/2023 DOCKET NO.: E-7 Sub 1276

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Alan Jenkins

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APPEARANCE ON BEHALF OF: The Commercial Group

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PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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DATE: August 22, 2023 DOCKET NO.: E-7, SUb 1276

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ADDRESS: 130 S. Salisbury Street

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Sierra Club

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 22, 2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Andrea C. Bonvecchio

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ADDRESS: 130 S. Salisbury Street

CITY: Raleigh STATE: NC ZIP CODE: 27601

APPEARANCE ON BEHALF OF: Sierra Club

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 28, 2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: David L. Neal, Senior Attorney

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APPEARANCE ON BEHALF OF: North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar (NCJC, et al.)

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 08/28/2023 DOCKET NO.: E-7, Sub 1276

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APPEARANCE ON BEHALF OF: North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 05/04/2023 DOCKET NO.: E-2 Sub 1300

ATTORNEY NAME and TITLE: Thomas Gooding, Associate Attorney

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CITY: Chapel Hill STATE: NC ZIP CODE: 27516

APPEARANCE ON BEHALF OF: North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Vote Solar

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 08/22/2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Matthew D. Quinn, Partner

FIRM NAME: Lewis & Roberts, PLLC

ADDRESS: P. O. Box 17529

CITY: Raleigh STATE: NC ZIP CODE: 27619

APPEARANCE ON BEHALF OF: NC WARN

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8-28-2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Kurt Boehm

FIRM NAME: Boehm, Kurtz & Lowry

ADDRESS: 36 East Seventh Street, Suite 1510

CITY: Cincinnati STATE: Ohio ZIP CODE: 45202

APPEARANCE ON BEHALF OF: Kroger Co. and Harris Teeter

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 25, 2023 DOCKET NO.: E-7 Sub 1276

ATTORNEY NAME and TITLE: Jody Kyler Cohn, Esq.

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CITY: Cincinnati STATE: Ohio ZIP CODE: 45202

APPEARANCE ON BEHALF OF: The Kroger Company

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 08/25/2023 DOCKET NO.: E-2 Sub1300

ATTORNEY NAME and TITLE: Benjamin M. Royster, Attorney

FIRM NAME: Royster & Royster PLLC

ADDRESS: 851 Marshall St.

CITY: Mt. Airy STATE: NC ZIP CODE: 27030

APPEARANCE ON BEHALF OF: Kroger Co. and Harris Teeter

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: x

PROTESTANT: ___ RESPONDENT: ___ DEFENDANT: ___

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APPEARANCE SLIP

DATE: 8-28-23 **DOCKET NO.:** E-7, Sub 1276

ATTORNEY NAME and TITLE: Marcus W. Trathen

FIRM NAME: Brooks Pierce McLendon Humphrey & Leonard, LLP

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CITY: Raleigh **STATE:** NC **ZIP CODE:** 27601

APPEARANCE ON BEHALF OF: Andale, LLC

APPLICANT: ___ **COMPLAINANT:** ___ **INTERVENOR:** X

PROTESTANT: ___ **RESPONDENT:** ___ **DEFENDANT:** ___

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: 8/28/2023 DOCKET NO.: E-7, Sub 1276

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Assistant Attorney General

FIRM NAME: North Carolina Attorney General's Office

ADDRESS: 114 West Edenton Street

CITY: Raleigh STATE: NC ZIP CODE: 27602

APPEARANCE ON BEHALF OF: The using and consuming public; the State and its citizens

APPLICANT: ___ COMPLAINANT: ___ INTERVENOR: X

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NORTH CAROLINA UTILITIES COMMISSION

APPEARANCE SLIP

DATE: August 28, 2023 DOCKET NO.: E-7, Sub 1276

ATTORNEY NAME and TITLE: Derrick C. Mertz, Special Deputy Attorney General;

FIRM NAME: North Carolina Department of Justice

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APPEARANCE ON BEHALF OF: The using and consuming public pursuant to N.C.G.S. sec. 62-20, and on behalf of the State of North Carolina and its citizens pursuant to N.C.G.S. sec. 114-2(8)

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NORTH CAROLINA UTILITIES COMMISSION
PUBLIC STAFF - APPEARANCE SLIP

DATE August 28, 2023 DOCKET #: E-7, Sub 1276

PUBLIC STAFF ATTORNEY Lucy E. Edmondson; Robert B. Josey; Nadia L. Luhr; Thomas J. Felling; William E. H. Creech; William S.F. Freeman; Anne M. Keyworth

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/s/ Robert B. Josey

/s/ Nadia L. Luhr

/s/ Thomas J. Felling

/s/ William E. H. Creech

/s/ William Freeman /s/ Anne M. Keyworth

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MOODY'S INVESTORS SERVICE

OUTLOOK
10 November 2022

Send Your Feedback

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Regulated Electric and Gas Utilities – US

2023 outlook negative due to higher natural gas prices, inflation and rising interest rates

Summary

» **We have revised our outlook on the US regulated utilities sector to negative from stable.** We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These developments raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.

» **Natural gas prices, inflation and interest rates drive social risk.** High natural gas prices and inflation may persist into 2023, which could hurt cash flow recovery should regulators seek to limit the impact on customer bills by delaying recovery or approving lower rate increases. We still think most state regulators will remain supportive, but utilities and commissions will face heightened public scrutiny amid affordability concerns.

» **Financial metrics already under pressure with little cushion entering 2023.** The sector's aggregate funds from operations (FFO)-to-debt ratio has remained between 14% and 15% since 2019, and we estimate the ratio will be closer to 14% in 2023 with a high potential of temporarily falling below this level depending on how much and how widespread cost recovery is delayed.

» **Capital spending and dividends will be sustained at a steady clip, weighing on financial performance.** These adverse business conditions come at a time when we expect the sector to maintain elevated capital spending focused on reducing carbon emissions to make progress toward net zero goals and overall system reliability, while maintaining their dividend payouts.

» **What could change our outlook:** The outlook could return to stable if the sector's regulatory support remains intact, natural gas prices settle at a level where most utilities are able to fully recover fuel and purchased power costs without a delay beyond 12 months, overall inflation moderates, interest rates stabilize and/or the sector's aggregate (FFO)-to-debt ratio remains between 14% to 15%. We could change our outlook to positive if utility regulation turns broadly more credit supportive resulting in timelier cash flow recovery or we expect the sector's aggregate (FFO)-to-debt ratio to rise above 17% on a sustained basis.

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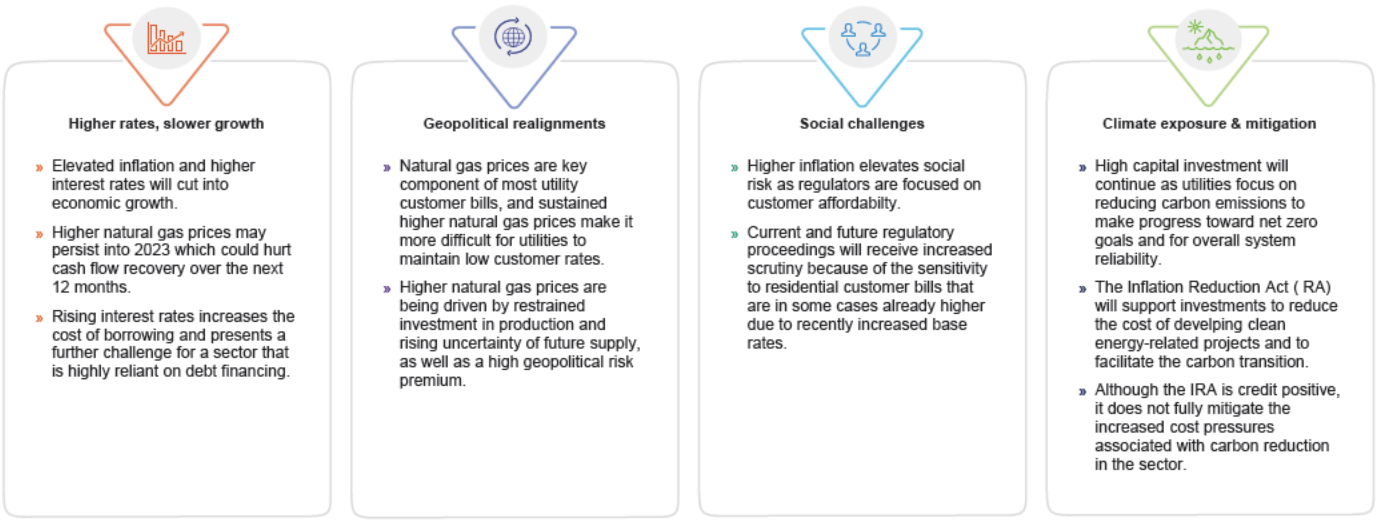
Outlook definition

The negative outlook reflects our view of credit fundamentals in the US regulated electric and gas utilities sector over the next 12 months. Sector outlooks are distinct from rating outlooks, which, in additional to sector dynamics, also reflects issuers' specific characteristics and actions. A sector outlook does not represent a sum of upgrades, downgrades or ratings under review or an average of rating outlooks.

High natural gas prices, inflation and interest rates increase social risk for utilities

We changed our outlook on the US regulated electric and gas utilities sector because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and interest rates. These considerations raise residential customer affordability issues, increasing the level of uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.

Exhibit 1
Global credit themes affecting US regulated electric and gas utilities in 2023



Source: Moody's Investors Service

High natural gas prices and inflation may persist into 2023, which could hurt cash flow recovery, especially if regulators seek to reduce the impact on customer bills and delay or otherwise limit full cost recovery of other operating expenses during general rate case proceedings. Under normal business and operating conditions, utilities are able to pass through purchased power and fuel costs to customers. While recovery periods vary, utilities typically recover commodity costs within 12 months through a filing outside of a general rate case.

Although regulatory cost recovery mechanisms remain unchanged, utilities have substantial purchased power and fuel costs to recoup in addition to rate base growth investments. These costs have the potential to lead to substantial rate hikes, increasing the risk that regulators will defer some cost recovery to later dates. The regulatory environment could turn less supportive, resulting in insufficient rate increases, a delay in the recovery of purchased power and fuel costs or costs being spread out over a longer period of time, which increases the time between expense and eventual recovery leading to a decline in near-term credit metrics. Utilities that operate in service territories with poor demographics or weak local economies are at higher risk because high inflation could limit the willingness of regulators to allow utilities to pass through their costs to customer all at once.

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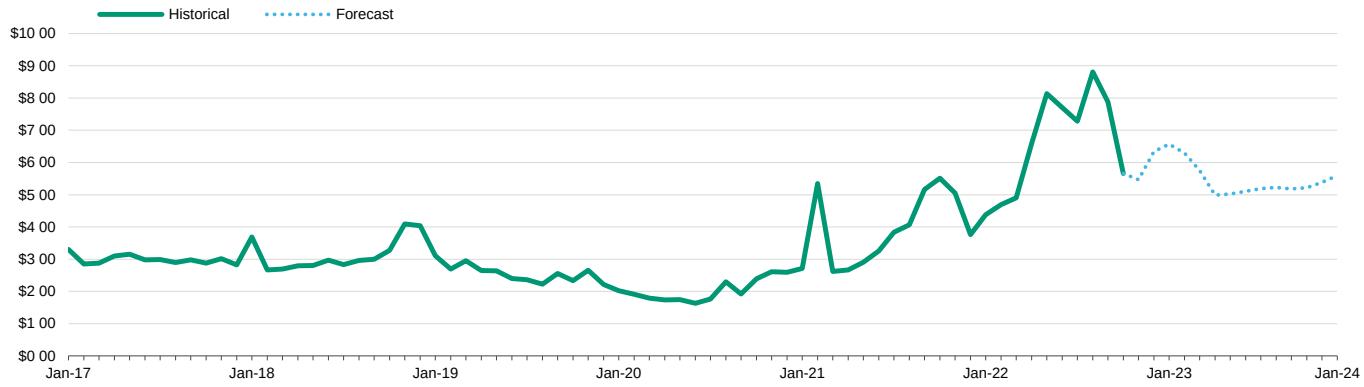
Affordability is an important credit analysis consideration in the demographic and societal trend category of our social risk classification for private-sector issuers. High natural gas prices, high inflation and rising interest rates have increased social risks, creating an adverse business environment for utilities that will persist into 2023. We expect utilities to work with regulators to structure rate plans that benefit both the utility and their customer base similar to Virginia Electric and Power Company (A2 stable) and Duke Energy Carolinas, LLC (A2 stable), which both agreed to recover their purchase power costs over a two- or three-year period. That said, the rise in social risks and affordability concerns could lead to degradation in regulatory support and adverse rate case outcomes.

Higher demand and low inventories have driven up natural gas prices, a key driver of most monthly residential electric and gas bills. While the average monthly spot price at Henry Hub mostly ranged between $3.00 and $5.00 per million British thermal units (MMBtu) through most of 2021, prices began to surge in early 2022 peaking at $8.81 MMBtu in August, a level not seen since 2008. Natural gas prices may sustain at higher levels through 2023 because of restrained investment in production and rising uncertainty about the expansion of future supplies, plus a high geopolitical risk premium (see Energy - Global Outlook - Widespread slowdown in demand and rising costs curtails earnings growth). As shown in Exhibit 2, the forward Henry Hub natural gas price curve is expected to remain above $5.00 MMBtu in 2023. We expect natural gas prices to be much higher than our medium-term Henry Hub natural gas price range of $2.50-$3.50/MMBtu in 2023 (see Europe's supply insecurity leads natural gas prices higher as US production costs rise). High natural gas prices make it difficult for utilities to maintain low customer rates, particularly considering the rate increases they need to support large capital expenditure programs and measures to curb carbon emissions.

Exhibit 2

Persistently high natural gas prices are a key component of rising customer bills

Average monthly Henry Hub natural gas spot price per million British thermal units (MMBtu)



Forecast prices as of 8 November 2022

Source: US Energy Information Administration

Rising interest rates will increase financing costs

The US consumer price index (CPI) continues to rise despite the Federal Reserve's moves to tighten monetary policy. According to the October 2022 CPI, consumer prices increased 0.4% from September and 7.7% from the year-earlier period. In addition to dampening consumer sentiment, the continued rise in inflation makes it more likely that the Fed will continue raising interest rates, increasing the cost of borrowing for the capital- and debt-intensive utility sector (see US economy is slowing, but not so fast that Fed will jettison policy tightening).

For many years, regulated utilities enjoyed a long period of low natural gas prices and interest rates, enabling them to grow rate base substantially while keeping customer rates low. Because regulators are sensitive to electric and gas service affordability, particularly for residential customers, low gas prices and interest rates have facilitated a trend of constructive rate making and credit supportive regulatory outcomes.

We would consider returning our outlook to stable if the sector's regulatory support remains intact, and business conditions improve such that natural gas prices settle at a level where utilities are able to fully recover purchased power and fuel costs without delay beyond 12 months, overall inflation moderates, interest rates stabilize and/or the sector's aggregate (FFO)-to-debt ratio remains

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between 14% to 15%. We could change our outlook to positive if utility regulation turns broadly more credit supportive resulting in timelier cash flow recovery or we expect the sector's aggregate (FFO)-to-debt ratio rising above 17% on a sustained basis.

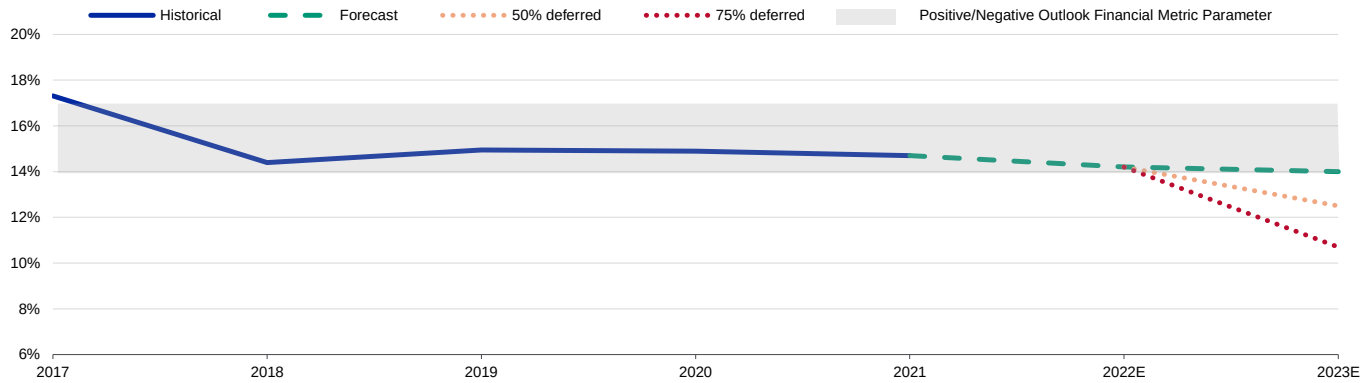
Financial metrics are under pressure with little cushion entering 2023

The sector's aggregate (FFO)-to-debt ratio settled between 14% and 15%, as seen in Exhibit 3, after declining from the high teens following the impact of Tax Reform in 2017 and increased debt issuance to support high capital expenditures. We estimate that the ratio will be closer to 14% in 2023 and that it is likely to temporarily fall below this level depending on how widespread the delay becomes for purchase power, fuel or other operating expenses. Although we typically look through business cycles that result in weaker financial metrics, our analysis of individual utilities will focus on their ability to maintain strong regulatory support for overall cost recovery and how quickly financial metrics will improve.

Exhibit 3

Widespread cost recovery delays could temporarily weaken financial metrics

Historical and forecast aggregate ratio of (FFO)-to-debt for rated US investor owned utility sector



Forecast scenario assumes full recovery of purchased power, fuel costs and operating expenses within 12 months
Down cases assume a 50% or 75% deferral of purchase power beyond 12 months and minimal rate increases
Source: Moody's Investors Service

The average allowed return on equity (ROE) remains relatively flat at about 9.45%, compared to 9.5% in 2021. We expect ROEs to be sustained at current levels through 2023 because most requests for rate increases have been approved without lowering ROEs, as was common in many previous rate cases. Rising interest rates could lead to higher ROEs in some instances, although there is likely to be a lag because of the timing of rate cases, which typically take up to a year to resolve. In addition, the aggregate earned ROE lags the allowed ROE by about 70 basis points because of the large number of deferrals related to one-time costs incurred since 2020 for the coronavirus pandemic, wildfires, storms and delays in general rate case filings during the pandemic. Regulatory asset balances for these costs also add pressure on ratepayers. Regulators could delay the pace of recovery of these items as a lever to minimize the impact on customer bills as has been the case for New York utilities over the past several years. The commission used rate modifiers and extended regulatory asset recovery to keep customer bill increases at 2%. This resulted in significant lag in cash flow recovery, leading to weaker credit metrics and ultimately driving rating downgrades of the New York utilities.

Utilities were well positioned to manage through a short period of higher natural gas prices because of their procurement strategies, which include both physical and financial hedging that was mostly done during a period of lower spot prices in 2021. Because natural gas prices have remained at higher levels for an extended period of time, procurement of natural gas at these higher prices has resulted in ballooning purchased power and fuel cost balances that make it more difficult to pass through to customers all at once particularly during a period of high inflation and rising interest rates. Current and future rate case filings and other regulatory requests will likely experience heightened scrutiny because of the sensitivity of increasing residential customer bills. These bills had already been rising because of increased base rates.

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Capital spending and dividends will be sustained at steady clip, weighing on financial performance

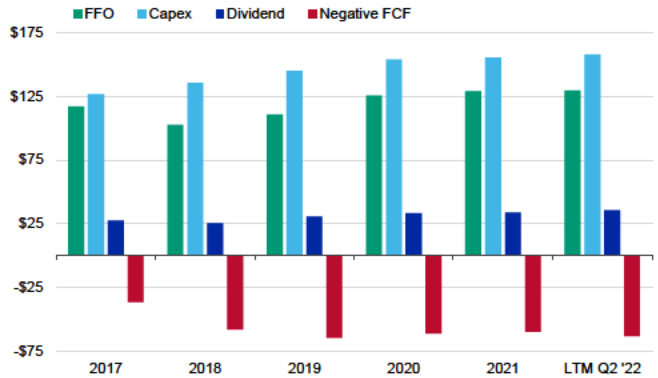
Utilities are likely to maintain their high levels of capital spending as they focus on reducing carbon emissions to further their progress toward net-zero targets and invest in overall system resilience (see Environmental risks drive capital spending increases, pressuring credit quality). Following the passage of the US Inflation Reduction Act of 2022, capital expenditures could increase even further because the legislation will reduce the cost of developing clean energy-related projects and help facilitate the sector's carbon transition (see Inflation Reduction Act's renewable, nuclear and other energy credits are credit positive). Although credit positive, the Inflation Reduction Act's provisions are not sufficient to offset the combined adverse effects of high natural gas prices, inflation and rising interest rates. While the sector is willing to issue more equity than it has in the recent past (such as through the use of at-the-market programs), debt issuance and even asset sale proceeds will drive the funding of capital spending programs with limited new common equity issuance, despite the relatively high valuations of most regulated utilities.

The sector has benefitted from regulatory outcomes that have supported rate base growth over the years. As shown in Exhibit 4, growth in FFO and capital spending has been relatively steady since 2017 because regulators have generally authorized timely recovery of prudent investments. This favorable business environment benefitted from a strong US economy, low natural gas prices and low interest rates, providing the means for companies to grow their dividend payments by about 5.2% since 2017. At the same time, the sector has experienced a substantial growth in negative free cash flow (FCF) of about 11.5% since 2017, which has contributed to the growth in total debt shown in Exhibit 5. Utility subsidiaries have some flexibility to absorb cost pressures by cutting back on capital spending and reducing dividends should there be a need to respond to an adverse regulatory climate. However, holding companies generally have little to no cushion in their financial metrics in light of the sector's continued high parent leverage to support capital expenditures and dividends.

Exhibit 4

Steadily increasing capital investment and dividend payout weighing on financial metrics

Historical FFO, capital expenditures, dividend and negative FCF for rated US investor owned utility sector

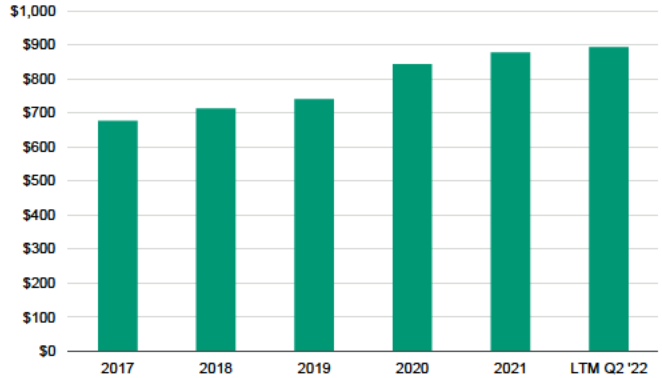


5-year CAGR: FFO - 2.0%, Capex - 4.5%, Dividend - 5.2%, Negative FCF - 11.5%
($ billions)
Source: Moody's Investors Service

Exhibit 5

Sector's total debt has increased to fund capital investment and negative free cash flow

Historical aggregate total debt for rated US investor owned utility sector



5-year CAGR - 5.7%
($ billions)
Source: Moody's Investors Service

Although the US investor-owned utility sector is facing significant headwinds, it continues to benefit from the fact that they operate critical infrastructure assets and are subject to strong regulation. The sector continues to experience relatively high equity valuations and strong capital markets access because it is often the sector that is most favored by investors in times of stress, as most recently seen during the volatile market conditions caused by the coronavirus pandemic in early 2020. Additionally, utilities maintain robust liquidity profiles through readily available multiyear facilities with modest covenant terms.

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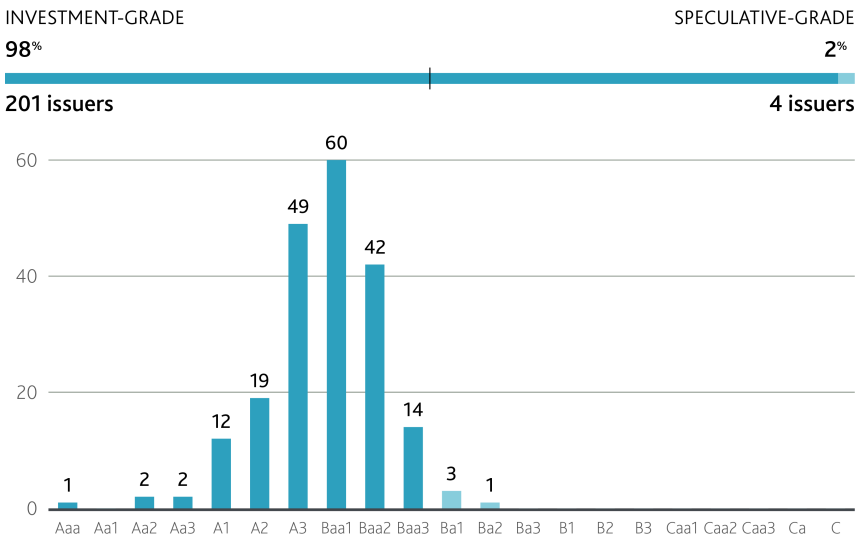
Appendix A

Exhibit 6

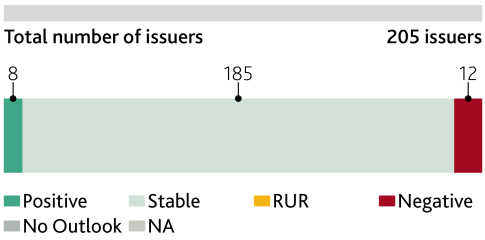
Distribution of long-term ratings and rating outlooks for US regulated electric and gas utilities

Ratings and rating outlooks distribution by number of issuers as of 1 November 2022

RATING DISTRIBUTION BY NUMBER OF ISSUERS



OUTLOOK DISTRIBUTION



Includes holding companies and operating subsidiaries.
Source: Moody's Investors Service

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Appendix B

Exhibit 7

Utility holding companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
Berkshire Hathaway Energy Company	A3 stable	$ 8,634	$ 54,716	16%	$ 7,309	$ -
Vectren Utility Holdings, Inc.	A3 stable	$ 445	$ 2,461	18%	$ 633	$ 40
NextEra Energy, Inc.	(P)Baa1 stable	$ 9,415	$ 63,407	15%	$ 16,377	$ 3,184
Ameren Corporation	Baa1 stable	$ 2,367	$ 14,650	16%	$ 3,316	$ 588
OGE Energy Corp.	Baa1 stable	$ 733	$ 5,033	15%	$ 881	$ 327
PPL Corporation[1]	Baa1 stable	$ 1,909	$ 13,784	14%	$ 2,035	$ 1,092
WEC Energy Group, Inc.	Baa1 stable	$ 2,485	$ 15,376	16%	$ 2,282	$ 886
Xcel Energy Inc.	Baa1 stable	$ 4,058	$ 24,209	17%	$ 4,349	$ 972
Eversource Energy	Baa1 negative	$ 2,560	$ 21,842	12%	$ 3,666	$ 831
Pinnacle West Capital Corporation	Baa1 negative	$ 1,205	$ 8,013	15%	$ 1,510	$ 375
Alliant Energy Corporation	Baa2 stable	$ 1,172	$ 8,394	14%	$ 1,304	$ 415
American Electric Power Company, Inc.	Baa2 stable	$ 5,391	$ 38,267	14%	$ 6,442	$ 1,577
Avangrid, Inc.	Baa2 stable	$ 1,497	$ 8,995	17%	$ 2,908	$ 681
Black Hills Corporation	Baa2 stable	$ 704	$ 4,488	16%	$ 652	$ 151
CenterPoint Energy, Inc.	Baa2 stable	$ 2,283	$ 15,658	15%	$ 3,929	$ 416
CMS Energy Corporation	Baa2 stable	$ 1,873	$ 12,223	15%	$ 2,300	$ 529
Consolidated Edison, Inc.	Baa2 stable	$ 3,913	$ 26,230	15%	$ 4,243	$ 1,067
Dominion Energy, Inc.	Baa2 stable	$ 5,039	$ 45,421	11%	$ 6,670	$ 2,116
DTE Energy Company	Baa2 stable	$ 2,366	$ 19,312	12%	$ 3,385	$ 713
Duke Energy Corporation	Baa2 stable	$ 10,516	$ 72,528	14%	$ 11,160	$ 3,147
Evergy, Inc.	Baa2 stable	$ 2,004	$ 12,899	16%	$ 2,223	$ 517
Exelon Corporation	Baa2 stable	$ 5,176	$ 42,511	12%	$ 8,146	$ 1,413
IDACORP, Inc.	Baa2 stable	$ 337	$ 2,646	13%	$ 354	$ 150
NiSource Inc.	Baa2 stable	$ 1,506	$ 10,950	14%	$ 1,997	$ 363
Otter Tail Corporation	Baa2 stable	$ 409	$ 949	43%	$ 170	$ 67
Public Service Enterprise Group Incorporated	Baa2 stable	$ 2,732	$ 21,368	13%	$ 2,946	$ 1,056
Sempra Energy	Baa2 stable	$ 4,498	$ 27,118	17%	$ 4,968	$ 1,408
Southern Company (The)	Baa2 stable	$ 7,979	$ 54,354	15%	$ 8,416	$ 2,825
Southwest Gas Holdings, Inc.	Baa2 stable	$ 666	$ 6,424	10%	$ 761	$ 149
Spire Inc.	Baa2 stable	$ 426	$ 4,320	10%	$ 569	$ 140
Unitil Corporation	Baa2 stable	$ 126	$ 619	20%	$ 120	$ 25
Entergy Corporation	Baa2 negative	$ 3,223	$ 29,060	11%	$ 6,375	$ 804

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Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
Edison International	Baa3 positive	$ 3,085	$ 30,725	10%	$ 5,610	$ 1,018
Cleco Corporate Holdings LLC	Baa3 stable	$ 345	$ 3,900	9%	$ 278	$ 133
Duquesne Light Holdings, Inc.	Baa3 stable	$ 388	$ 2,783	14%	$ 375	$ 58
Emera Inc.	Baa3 negative	$ 1,127	$ 13,214	8%	$ 1,902	$ 363
Fortis Inc.	Baa3 stable	$ 2,477	$ 21,943	11%	$ 2,845	$ 502
PNM Resources, Inc.	Baa3 stable	$ 605	$ 4,194	14%	$ 643	$ 116
Puget Energy, Inc.	Baa3 stable	$ 830	$ 7,064	12%	$ 983	$ 62
IPALCO Enterprises, Inc.	Baa3 stable	$ 344	$ 2,970	12%	$ 415	$ 139
FirstEnergy Corp.	Ba1 positive	$ 2,675	$ 24,027	11%	$ 2,714	$ 880
DPL Inc.	Ba1 negative	$ 114	$ 1,638	7%	$ 243	$ -
PG&E Corporation	Ba2 stable *	$ 5,542	$ 50,803	11%	$ 9,116	$ -

All ratios are based on GAAP "Adjusted" financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations, but may not include all analytical adjustments.
List excludes intermediate holding companies unless the ultimate parent company is excluded from the holding company peer group (e.g. AES Corporation) or is domiciled outside of the US.
[1] PPL Corp.'s credit metric includes the total debt but partial cash flow from NECO due to the timing of the completed acquisition.
*PG&E Corporation is a Corporate Family Rating
Source: Moody's Investors Service

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Exhibit 8

Vertically integrated operating companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
Alabama Power Company	A1 stable	$ 2,125	$ 10,079	21%	$ 2,137	$ 1,000
Consumers Energy Company	A1 stable*	$ 2,133	$ 8,691	25%	$ 2,233	$ 775
Florida Power & Light Company	A1 stable	$ 6,808	$ 21,535	32%	$ 8,264	$ 2,105
Madison Gas and Electric Company	A1 stable	$ 173	$ 689	25%	$ 144	$ 17
MidAmerican Energy Company	A1 stable	$ 1,934	$ 7,836	25%	$ 2,054	$ -
Southern Indiana Gas & Electric Company	A1 stable	$ 229	$ 1,004	23%	$ 310	$ 30
DTE Electric Company	A2 stable	$ 2,007	$ 10,611	19%	$ 2,730	$ 734
Duke Energy Carolinas, LLC	A2 stable	$ 3,291	$ 14,303	23%	$ 3,163	$ -
Duke Energy Indiana, LLC.	A2 stable	$ 1,096	$ 5,023	22%	$ 941	$ 362
Duke Energy Progress, LLC	A2 stable	$ 2,286	$ 11,093	21%	$ 2,077	$ 950
Northern States Power Company (Minnesota)	A2 stable	$ 1,234	$ 7,025	18%	$ 1,780	$ 478
Northern States Power Company (Wisconsin)	A2 stable	$ 250	$ 1,058	24%	$ 308	$ 113
Virginia Electric and Power Company	A2 stable	$ 3,386	$ 17,622	19%	$ 4,066	$ -
Wisconsin Electric Power Company [1]	A2 stable	$ 853	$ 6,125	14%	$ 914	$ 580
Wisconsin Public Service Corporation	A2 stable	$ 459	$ 1,885	24%	$ 399	$ 260
Indiana Michigan Power Company	A3 positive	$ 849	$ 3,420	25%	$ 726	$ 200
Cleco Power LLC	A3 stable	$ 231	$ 2,173	11%	$ 269	$ 52
Duke Energy Florida, LLC.	A3 stable	$ 1,984	$ 9,252	21%	$ 2,145	$ -
Kentucky Utilities Co.	A3 stable	$ 699	$ 2,983	23%	$ 608	$ 298
Louisville Gas & Electric Company	A3 stable	$ 567	$ 2,419	23%	$ 439	$ 219
Oklahoma Gas & Electric Company	A3 stable	$ 962	$ 4,137	23%	$ 880	$ 265
Otter Tail Power Company	A3 stable	$ 180	$ 823	22%	$ 136	$ 53
PacifiCorp	A3 stable	$ 1,710	$ 8,799	19%	$ 1,567	$ 250
Portland General Electric Company	A3 stable	$ 584	$ 3,616	16%	$ 666	$ 154
Public Service Company of Colorado	A3 stable	$ 1,403	$ 7,073	20%	$ 1,792	$ 479
Tucson Electric Power Company	A3 stable	$ 525	$ 2,333	23%	$ 527	$ 63
Wisconsin Power and Light Company	A3 stable	$ 367	$ 2,806	13%	$ 824	$ 172
Tampa Electric Company	A3 negative	$ 938	$ 4,397	21%	$ 1,399	$ 471
Arizona Public Service Company	A3 negative	$ 1,242	$ 7,014	18%	$ 1,495	$ 382
Entergy Arkansas, LLC	Baa1 positive	$ 858	$ 4,763	18%	$ 994	$ 86
Entergy Mississippi, LLC	Baa1 positive	$ 487	$ 2,553	19%	$ 664	$ -
Union Electric Company	(P)Baa1 stable	$ 1,071	$ 6,445	17%	$ 1,772	$ 24
Appalachian Power Company	Baa1 stable	$ 911	$ 5,490	17%	$ 943	$ 75
Duke Energy Kentucky, Inc.	Baa1 stable	$ 134	$ 853	16%	$ 164	$ -
Empire District Electric Company (The)	Baa1 stable	$ 231	$ 1,200	19%	$ 318	$ -
Evergy Kansas Central, Inc.	Baa1 stable	$ 976	$ 5,326	18%	$ 914	$ 465
Evergy Metro, Inc.	Baa1 stable	$ 758	$ 3,498	22%	$ 793	$ 50
Georgia Power Company	Baa1 stable	$ 2,610	$ 15,076	17%	$ 3,916	$ 1,670
Hawaiian Electric Company, Inc.	Baa1 stable	$ 413	$ 2,183	19%	$ 301	$ 119
Idaho Power Company	Baa1 stable	$ 289	$ 2,646	11%	$ 354	$ 150

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Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
Indianapolis Power & Light Company	Baa1 stable	$ 370	$ 2,097	18%	$ 414	$ 162
Interstate Power and Light Company	Baa1 stable	$ 667	$ 3,774	18%	$ 365	$ 360
Mississippi Power Company	Baa1 stable	$ 383	$ 1,572	24%	$ 225	$ 163
Nevada Power Company	Baa1 stable	$ 722	$ 3,115	23%	$ 579	$ 200
Newfoundland Power Inc.	Baa1 stable	$ 102	$ 537	19%	$ 103	$ 27
Northern Indiana Public Service Company	Baa1 stable	$ 817	$ 2,992	27%	$ 821	$ -
Public Service Company of Oklahoma	Baa1 stable	$ 389	$ 2,950	13%	$ 396	$ 10
Puget Sound Energy, Inc.	Baa1 stable	$ 867	$ 5,175	17%	$ 954	$ 149
Sierra Pacific Power Company	Baa1 stable	$ 242	$ 1,278	19%	$ 370	$ 70
Superior Water, Light and Power Company	Baa1 stable	$ 14	$ 50	27%	$ 13	$ -
ALLETE, Inc.	Baa1 stable	$ 317	$ 2,167	15%	$ 276	$ 138
Entergy Louisiana, LLC	Baa1 negative	$ 1,030	$ 10,727	10%	$ 3,622	$ 185
Dominion Energy South Carolina, Inc.	Baa2 positive	$ 715	$ 4,737	15%	$ 698	$ 301
NorthWestern Corporation	Baa2 stable	$ 357	$ 2,633	14%	$ 487	$ 133
Avista Corp.	(P)Baa2 stable	$ 304	$ 2,671	11%	$ 442	$ 124
El Paso Electric Company	Baa2 stable	$ 259	$ 1,887	14%	$ 387	$ 130
Entergy Texas, Inc.	Baa2 stable	$ 568	$ 2,782	20%	$ 602	$ -
Evergy Missouri West, Inc.	Baa2 stable	$ 263	$ 1,706	15%	$ 490	$ -
Liberty Utilities Co.	Baa2 stable	$ 399	$ 2,631	15%	$ 667	$ -
Monongahela Power Company	Baa2 stable	$ 195	$ 2,006	10%	$ 249	$ 106
Public Service Company of New Mexico	Baa2 stable	$ 406	$ 2,043	20%	$ 675	$ 61
Southwestern Electric Power Company	Baa2 stable	$ 520	$ 3,941	13%	$ 499	$ 17
Southwestern Public Service Company	Baa2 stable	$ 647	$ 3,252	20%	$ 507	$ 290
Avista Corp.	(P)Baa2 stable	$ 304	$ 2,671	11%	$ 442	$ 124
Pacific Gas & Electric Company	Baa3 stable*	$ 5,817	$ 46,149	13%	$ 9,091	$ 425
Alaska Electric Light and Power Company(AELP)	Baa3 stable	$ 16	$ 122	13%	$ 5	$ 6
Kentucky Power Company	Baa3 stable	$ 132	$ 1,245	11%	$ 200	$ -
Entergy New Orleans, LLC.	Ba1 negative	$ 128	$ 868	15%	$ 242	$ -

All ratios are based on GAAP "Adjusted" financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations, but may not include all analytical adjustments.
[1] These ratios do not reflect the adjustments related to the Power the Future lease agreements.
*First mortgage bond rating
Source: Moody's Investors Service

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Exhibit 9

Transmission and distribution operating companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
NSTAR Electric Company	A1 negative	$ 885	$ 4,547	19%	$ 1,030	$ 144
Oncor Electric Delivery Company LLC	A2 stable*	$ 1,790	$ 11,931	15%	$ 2,736	$ 859
PECO Energy Company	A2 stable	$ 927	$ 4,515	21%	$ 1,321	$ 370
Ameren Illinois Company	(P)A3 stable	$ 1,159	$ 4,551	25%	$ 1,485	$ -
Baltimore Gas and Electric Company	A3 stable	$ 894	$ 4,475	20%	$ 1,213	$ 296
Commonwealth Edison Company	A3 stable	$ 1,548	$ 10,675	15%	$ 2,436	$ 543
Connecticut Light and Power Company (The)	A3 stable	$ 897	$ 4,349	21%	$ 909	$ 347
Duquesne Light Company	A3 stable	$ 389	$ 1,454	27%	$ 357	$ 60
FortisBC Energy Inc.	A3 stable	$ 332	$ 2,610	12%	$ 461	$ 133
Hydro One Inc.	A3 stable	$ 1,724	$ 11,492	15%	$ 1,547	$ 503
Jersey Central Power & Light Company	A3 stable	$ 559	$ 2,366	24%	$ 371	$ 105
Metropolitan Edison Company	A3 stable	$ 257	$ 1,172	22%	$ 143	$ 145
Narragansett Electric Company	A3 stable	$ 259	$ 1,544	17%	$ 379	$ -
Ohio Edison Company	A3 stable	$ 366	$ 1,266	29%	$ 285	$ 271
Pennsylvania Power Company	A3 stable	$ 61	$ 267	23%	$ 41	$ 26
PPL Electric Utilities Corporation	A3 stable	$ 916	$ 4,486	20%	$ 897	$ 298
Public Service Company of New Hampshire	A3 stable	$ 336	$ 1,756	19%	$ 452	$ 102
Public Service Electric and Gas Company	A3 stable	$ 1,973	$ 12,528	16%	$ 2,627	$ -
West Penn Power Company	A3 stable	$ 238	$ 1,018	23%	$ 190	$ 90
San Diego Gas & Electric Company	(P)A3 stable	$ 1,750	$ 9,204	19%	$ 2,266	$ 300
United Illuminating Company	Baa1 positive	$ 237	$ 1,131	21%	$ 215	$ 115
Atlantic City Electric Company	Baa1 stable	$ 335	$ 1,769	19%	$ 394	$ 97
CenterPoint Energy Houston Electric, LLC	Baa1 stable	$ 943	$ 6,170	15%	$ 2,272	$ 67
Central Hudson Gas & Electric Corporation	Baa1 stable	$ 124	$ 1,079	11%	$ 227	$ -
Consolidated Edison Company of New York, Inc.	Baa1 stable	$ 3,326	$ 21,065	16%	$ 3,818	$ 984
Delmarva Power & Light Company	Baa1 stable	$ 397	$ 1,995	20%	$ 422	$ 140
Duke Energy Ohio, Inc.	Baa1 stable	$ 568	$ 3,834	15%	$ 829	$ -
Fitchburg Gas & Electric Light Company	Baa1 stable	$ 32	$ 161	20%	$ 27	$ 6
FortisAlberta Inc.	Baa1 stable	$ 296	$ 1,915	15%	$ 302	$ 69
Massachusetts Electric Company	Baa1 stable	$ 192	$ 1,940	10%	$ 344	$ -
New York State Electric and Gas Corporation	Baa1 stable	$ 123	$ 2,285	5%	$ 756	$ 270
Niagara Mohawk Power Corporation	Baa1 stable	$ 729	$ 4,025	18%	$ 900	$ 275
Ohio Power Company	Baa1 stable	$ 561	$ 3,512	16%	$ 777	$ 86
Pennsylvania Electric Company	Baa1 stable	$ 257	$ 1,545	17%	$ 147	$ 265
Potomac Electric Power Company	Baa1 stable	$ 542	$ 3,765	14%	$ 817	$ 445
Rochester Gas & Electric Corporation	Baa1 stable	$ 164	$ 1,547	11%	$ 435	$ 250
Texas-New Mexico Power Company	Baa1 stable	$ 181	$ 1,110	16%	$ 396	$ -
Unitil Energy Systems, Inc.	Baa1 stable	$ 35	$ 127	27%	$ 23	$ 5

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Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
Southern California Edison Company	Baa2 positive	$ 3,228	$ 26,762	12%	$ 5,610	$ 1,085
AEP Texas Inc.	Baa2 stable	$ 747	$ 6,202	12%	$ 1,162	$ -
Electric Transmission Texas, LLC	Baa2 stable	$ 237	$ 1,601	15%	$ 122	$ 70
National Grid North America Inc.	Baa2 stable	$ 2,191	$ 20,609	11%	$ 4,171	$ -
National Grid USA	Baa2 stable	$ 1,948	$ 24,045	8%	$ 4,156	$ -
Orange and Rockland Utilities, Inc.	Baa2 stable	$ 185	$ 1,149	16%	$ 223	$ 54
Potomac Edison Company (The)	Baa2 stable	$ 174	$ 755	23%	$ 141	$ -
Toledo Edison Company	Baa2 stable	$ 102	$ 486	21%	$ 60	$ 47
Cleveland Electric Illuminating Company (The)	Baa3 stable	$ 209	$ 1,617	13%	$ 190	$ 53
Dayton Power & Light Company	Baa2 negative	$ 138	$ 766	18%	$ 241	$ 69

All ratios are based on GAAP "Adjusted" financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations, but may not include all analytical adjustments.
*First mortgage bond rating
Source: Moody's Investors Service

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Exhibit 10

Local gas distribution operating companies

Data for the most recent 12-month period available ($ millions)

Issuer	Rating and Outlook	CFO Pre-WC	Total Debt	CFO Pre-WC/Debt	Capex	Dividends
Atmos Energy Corporation	A1 stable	$ 1,357	$ 8,193	17%	$ 2,362	$ 362
New Jersey Natural Gas Company	A1 stable*	$ 295	$ 1,316	22%	$ 364	$ -
Spire Missouri Inc.	A1 negative *	$ 40	$ 2,039	2%	$ 362	$ -
Connecticut Natural Gas Corporation	A2 stable	$ 67	$ 276	24%	$ 69	$ 35
Northern Illinois Gas Company	A2 stable	$ 506	$ 2,383	21%	$ 736	$ -
Peoples Gas Light and Coke Company	A2 stable	$ 484	$ 1,964	25%	$ 536	$ 395
Southern California Gas Company	A2 stable	$ 1,154	$ 6,092	19%	$ 1,994	$ 25
Spire Alabama Inc.	A2 stable	$ 126	$ 839	15%	$ 148	$ 22
UGI Utilities, Inc.	A2 negative	$ 365	$ 1,541	24%	$ 432	$ -
Berkshire Gas Company	A3 stable	$ 10	$ 82	13%	$ 19	$ 10
CenterPoint Energy Resources Corp.	A3 stable	$ 909	$ 4,585	20%	$ 1,038	$ -
DTE Gas Company	A3 stable	$ 408	$ 2,091	20%	$ 604	$ 156
ONE Gas, Inc	A3 stable	$ 461	$ 4,242	11%	$ 540	$ 129
Piedmont Natural Gas Company, Inc.	A3 stable	$ 537	$ 3,415	16%	$ 821	$ -
Questar Gas Company	A3 stable	$ 207	$ 1,103	19%	$ 301	$ -
SEMCO Energy, Inc.	A3 stable	$ 126	$ 529	24%	$ 93	$ 30
South Jersey Gas Company	A3 stable	$ 253	$ 1,164	22%	$ 225	$ -
Southern Connecticut Gas Company	A3 stable	$ 34	$ 377	9%	$ 104	$ 30
UNS Gas, Inc.	A3 stable	$ 24	$ 105	22%	$ 27	$ -
Washington Gas Light Company	A3 stable	$ 325	$ 1,838	18%	$ 539	$ 100
Wisconsin Gas LLC	A3 negative	$ 174	$ 856	20%	$ 194	$ 50
Boston Gas Company	Baa1 stable	$ 500	$ 2,242	22%	$ 646	$ 43
FortisBC Inc.	Baa1 stable	$ 100	$ 1,002	10%	$ 109	$ 38
KeySpan Gas East Corporation	Baa1 stable	$ 256	$ 1,561	16%	$ 410	$ -
Northwest Natural Gas Company	(P)Baa1 stable	$ 199	$ 1,289	15%	$ 311	$ 58
PNG Companies LLC	Baa1 stable*	$ 264	$ 1,517	17%	$ 280	$ 75
Public Service Co. of North Carolina, Inc.	Baa1 stable	$ 146	$ 1,109	13%	$ 156	$ 92
Southern Company Gas Capital	Baa1 stable	$ 1,264	$ 8,181	15%	$ 1,437	$ 530
Southwest Gas Corporation	Baa1 stable	$ 484	$ 3,346	14%	$ 620	$ 118
Yankee Gas Services Company	Baa1 stable	$ 122	$ 907	13%	$ 236	$ 46
Northern Utilities, Inc.	Baa1 stable	$ 49	$ 270	18%	$ 62	$ 14
Boston Gas Company	Baa1 stable	$ 500	$ 2,242	22%	$ 646	$ 43
Brooklyn Union Gas Company, The	Baa2 stable	$ 261	$ 2,694	10%	$ 712	$ -

All ratios are based on GAAP "Adjusted" financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations, but may not include all analytical adjustments.

*First mortgage bond rating

Source: Moody's Investors Service

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Moody's related publications

Sector research

- Regulated Electric and Gas Utilities – US: Environmental risks drive capital spending increases, pressuring credit quality, 3 November 2022
- Regulated Electric Utilities – US: Regulatory support, storm cost recovery provisions to mitigate Hurricane Ian impact, 30 September 2022
- Electric Utilities and Power Companies – US: Inflation Reduction Act's renewable, nuclear and other energy credits are credit positive, 11 August 2022
- Government Policy – US: Inflation Reduction Act will build economic resilience, but its costs and benefits vary by sector, 10 August 2022
- Regulated Electric and Gas Utilities – US: Regulated cost recovery provides Dominion credit advantage versus offshore wind peers, 20 July 2022
- Regulated Electric and Gas Utilities – US: Offshore wind projects raise business risk, but credit implications depend on execution, 20 July 2022
- Regulated Electric and Gas Utilities – US: High natural gas prices, inflation and rising interest rates increase social risk, 13 June 2022
- Electric Utilities and Power Companies – US: Renewable energy developers and owners to benefit from solar tariff exemption 8 June 2022
- Regulated Electric and Gas Utilities – US: Persistent elevated electric and gas prices will increase social risks, 14 February 2022

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S&P Global
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Research

The Outlook For North American Regulated Utilities Turns Stable

May 18, 2023

Key Takeaways

S&P G oba Rat ngs has rev sed ts out ook for the nvestor owned North Amer can regu ated ut ty ndustry to stab e from negat ve.

Our reassessment fo ows three years n wh ch downgrades s gn f cant y outpaced upgrades.

S gn f cant r sks for the ndustry rema n, nc ud ng nf at on, record eve s of cap ta spend ng, and the pract ce of many compan es to operate w th m n ma f nanc a cush on from the r downgrade thresho ds.

We expect future downgrades and upgrades w be more ba anced over the next two years.

PRIMARY CREDIT ANALYST

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n ear y 2020, S&P G oba Rat ngs rev sed the out ook for the nvestor owned North Amer can regu ated ut ty ndustry to negat ve from stab e. Th s was the f rst t me n more than a decade that our out ook on the sector was negat ve. S nce 2020, downgrades outpaced upgrades by more than 3: , weaken ng the med an rat ng on the sector to BBB from A , the f rst t me ever that the med an rat ng was n the BBB category. Pr or to 2020, the ast year that the ndustry s downgrades outpaced upgrades was n 20 0.

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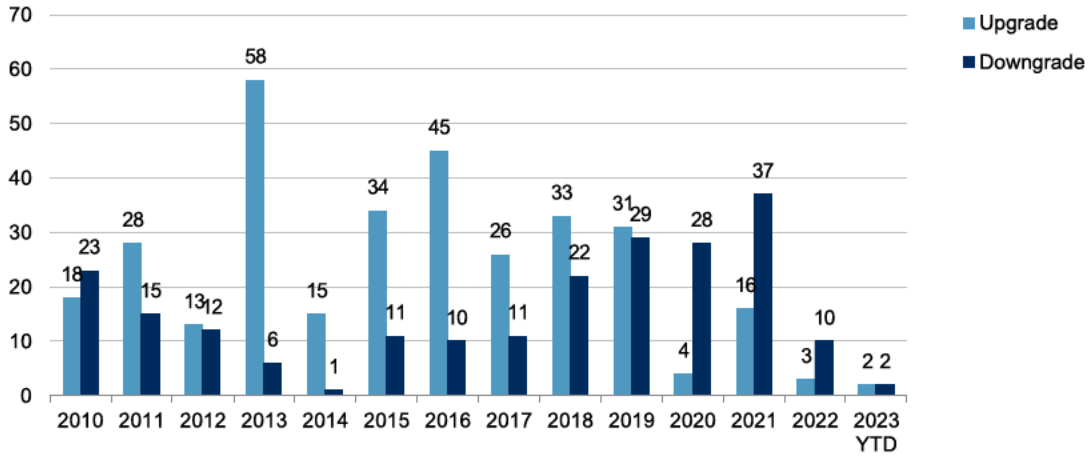
Chart 1

North American regulated utilities upgrade and downgrade comparison



As of May 15, 2023. Source: S&P Global Ratings.

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The Impact Of ESG Factors And High Capital Spending

Cred t qua ty weakened over the past three years pr mar y as a resu t of two deve opments. One s the ncreas ng nf uence of env ronmenta , soc a , and governance (ESG) cred t factors on our cred t ana ys s, wh ch cons ders compan es exposures to such factors as c mate r sks or governance structure. The other s h gh cap ta spend ng and the fa ure to fund such robust spend ng n a cred t support ve manner. Phys ca r sks such as exposure to w df res, storms, extreme temperature events, and hurr canes, rema ns a cons derab e r sk for the ndustry. n fact, over the past three years the U.S. exper enced ts h ghest eve of damages ever from phys ca r sks (chart 2). n response, the ndustry cont nues to proact ve y work w th regu ators, mp ement ng var ous cred t support ve too s. These n t at ves nc ude ncreas ng storm reserve accounts, se f nsurance, secur t zat on, system harden ng, and w df re m t gat on programs. Wh e these too s w reduce some of th s r sk, we expect that because of c mate change, the ndustry w a ways be somewhat vu nerab e to phys ca r sks that cou d potent a y harm cred t qua ty.

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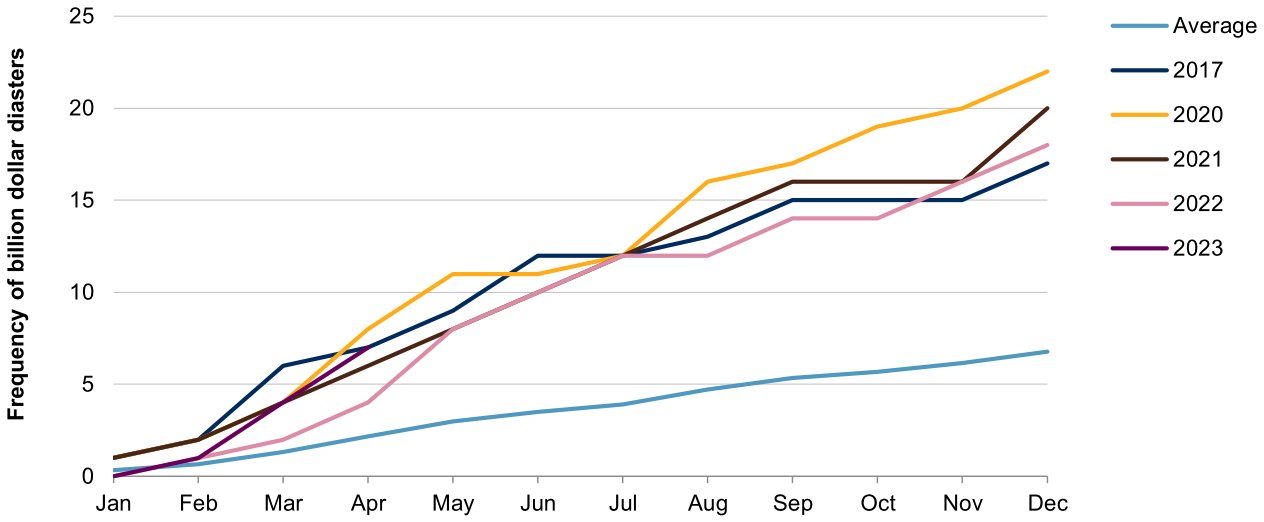
Chart 2

Frequency of U.S. billion dollar weather disasters



Average is 1980-2023. Source: National Oceanic and Atmospheric Administration.

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The ndustry s d sproport onate greenhouse gas (GHG) em ss ons compared to other ndustr es and governance def c enc es a so constra ned ts cred t qua ty over the past three years. n response, the ndustry took steps to c ose coa p ants, s gn f cant y ncrease ts re ance on renewab e energy, and reduce ts tota GHG em ss ons. Current y, a most a the compan es we rate have tang b e net zero em ss on targets and the ndustry has a ready reduced ts GHG em ss ons by over 30% dur ng the past decade, wh ch we v ew as support ve of cred t qua ty.

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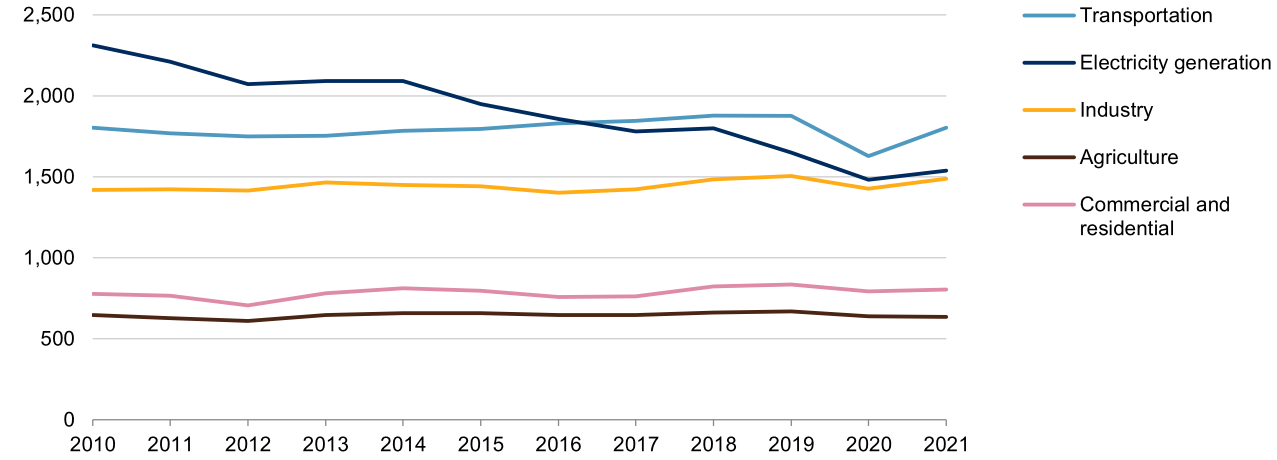
Chart 3

U.S. electric generation shows a significant reduction in GHG emissions



Source: U.S. Environmental Protection Agency.

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Over the past three years, two arge compan es exper enced mater a governance def c enc es, nc ud ng charges of br bery and nsuff c ent nterna contro s. S nce these nc dents, other ut t es have strengthened the r nterna contro s, reduc ng the ke hood that another mater a governance def c ency w be dent f ed w th n the ndustry. Overa , we be eve that ut t es have appropr ate nterna contro s n p ace and are un ke y to exper ence s m ar prob ems over the next two years.

nvestor owned North Amer ca regu ated ut t es (e ectr c, gas, and water) have ncreased the r spend ng exponent a y over the past two decades at a compounded annua growth rate of about 9%. We expect that the ndustry s cap ta spend ng for 2023 w reach a record at about $200 b on. We expect that ut t es w even s gn f cant y ncrease th s eve of spend ng over the next two decades, as they step up spend ng on safety, re ab ty, energy trans t on programs, and on n t at ves n support of e ectr c veh c es. As a resu t, the ndustry s annua negat ve d scret onary cash f ow s expected to cont nue to rema n cons stent y greater than $ 00 b on. Because ut t es have not cons stent y funded these def c ts n a cred t support ve manner, the ndustry s cred t measures and cred t qua ty have weakened.

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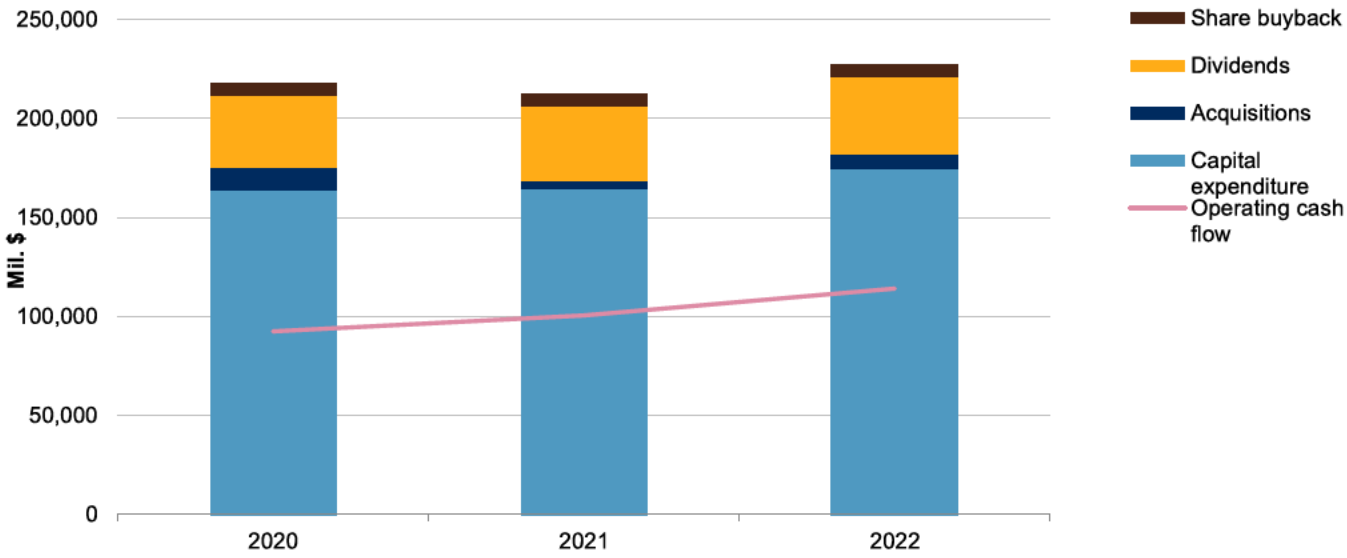
Chart 4

North American regulated utilities' reported cash flows and primary uses



Data represents North American investor-owned electric, gas and water utilities. Source: S&P Global Ratings.

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The Stable Industry Outlook Mirrors Improving Economic Conditions

Our out ook for the ndustry as a who e ref ects the ncreas ng percentage of ut t es w th a stab e out ook, ower natura gas pr ces, and a s ow ng of nf at on. At year end 2020, about 35% of the compan es we rate n the sector had a negat ve out ook compared w th on y about 4% as of May 2023. urthermore, for the f rst t me n years, the current percentage of ut t es w th a pos t ve out ook (4%) s the same percentage of those w th a negat ve out ook. Much of th s ups de ref ects the f nanc a cush on that compan es have after a downgrade and the more str ngent nterna contro s they ve mp emented fo ow ng the dent f cat on of severa governance def c enc es.

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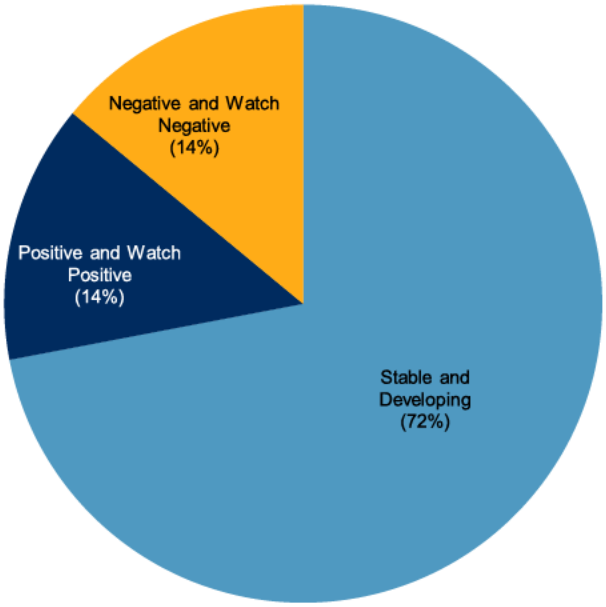
Chart 5

North American regulated utilities industry outlook 2023 YTD



Data as of May 15, 2023 Source: S&P Global Ratings.
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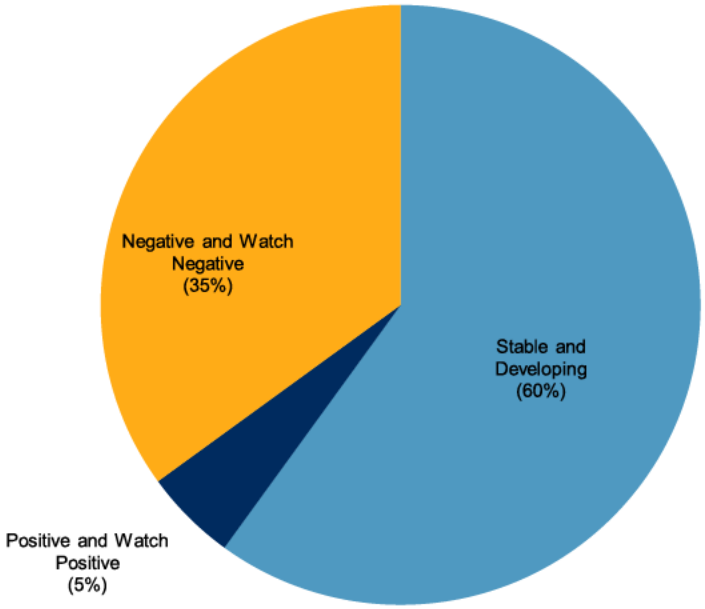
Chart 6

North American regulated utilities industry outlook 2020



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More recent y, econom c nd cators have gradua y mproved. nf at on s ncreas ng at a cons derab y s ower pace w th Apr s consumer pr ce ndex (CP) at 4.9% compared 9. % n June 2022. Add t ona y, natura gas pr ces have s gn f cant y retreated from August 2022 h ghs when pr ces at Henry Hub approx mated $9 per MMbtu. These hea th er econom c deve opments are cons stent w th S&P G oba econom sts forecast of CP at about 4.7% by year end 2023. Th s econom c strengthen ng s a so mportant for the ut ty ndustry. When gas pr ces peaked dur ng 2022, many ut t es deferred the recovery of these h gher costs and are on y now start ng to b ratepayers. The recent drop n natura gas pr ces prov des some customer b cush on, a ow ng the ut t es to b customers for the prev ous y deferred h gher commod ty costs w thout overwhe m ng the customer.

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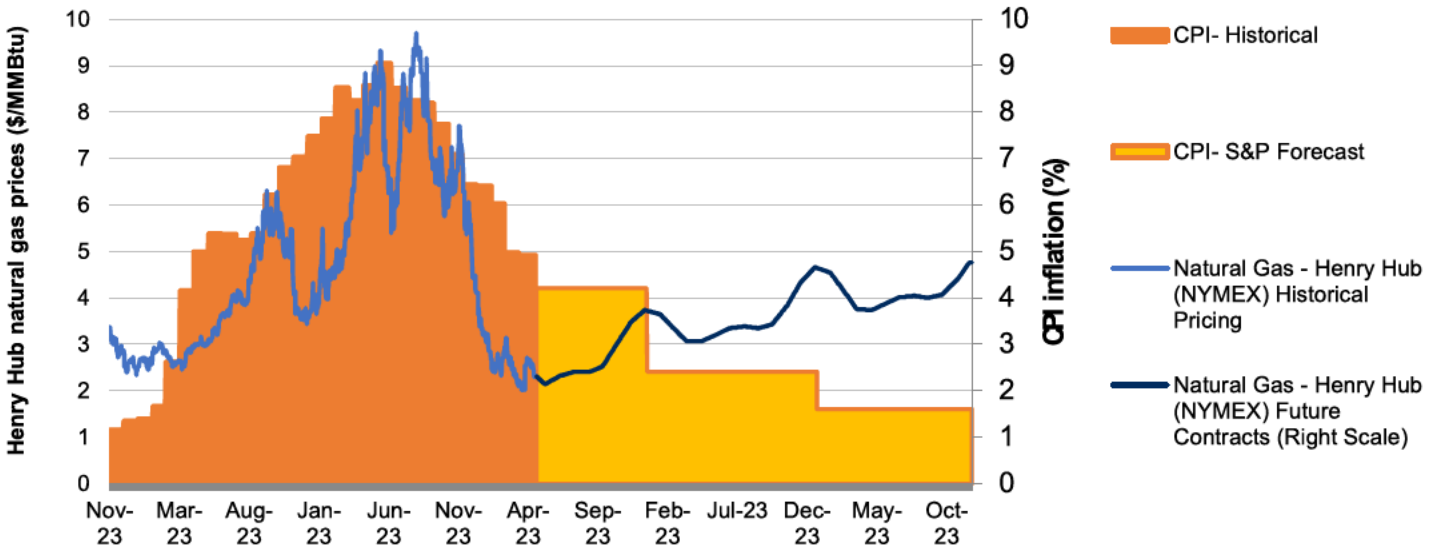
Chart 7

Natural gas prices and inflation



Source: As of May 1, 2023. CAP IQ; S&P Global Ratings, Economic Outlook U.S. Q2 2023: Still Resilient, Downside Risks Rise.

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A More Balanced Upgrade And Downgrade Scenario Going Forward

Desp te the mprovement n econom c data, we expect nf at on, r s ng nterest rates, h gher cap ta spend ng, and the strateg c dec s on by many compan es to operate w th on y m n ma f nanc a cush on from the r downgrade thresho ds to cont nue to pressure the ndustry s cred t qua ty. Throughout 2022 and so far n 2023, the edera Reserve has cons stent y ra sed nterest rates to reduce the pace of nf at on. Wh e these act ons appear to have had a pos t ve effect on s ow ng nf at on, there s st been a modest weaken ng n the ndustry s f nanc a measures because of nf at on and r s ng nterest rates. An env ronment of cont nuous y r s ng costs tends to weaken the ndustry s f nanc a measures because of the t m ng d fference between when the h gher costs are ncurred and when they are u t mate y recovered from ratepayers.

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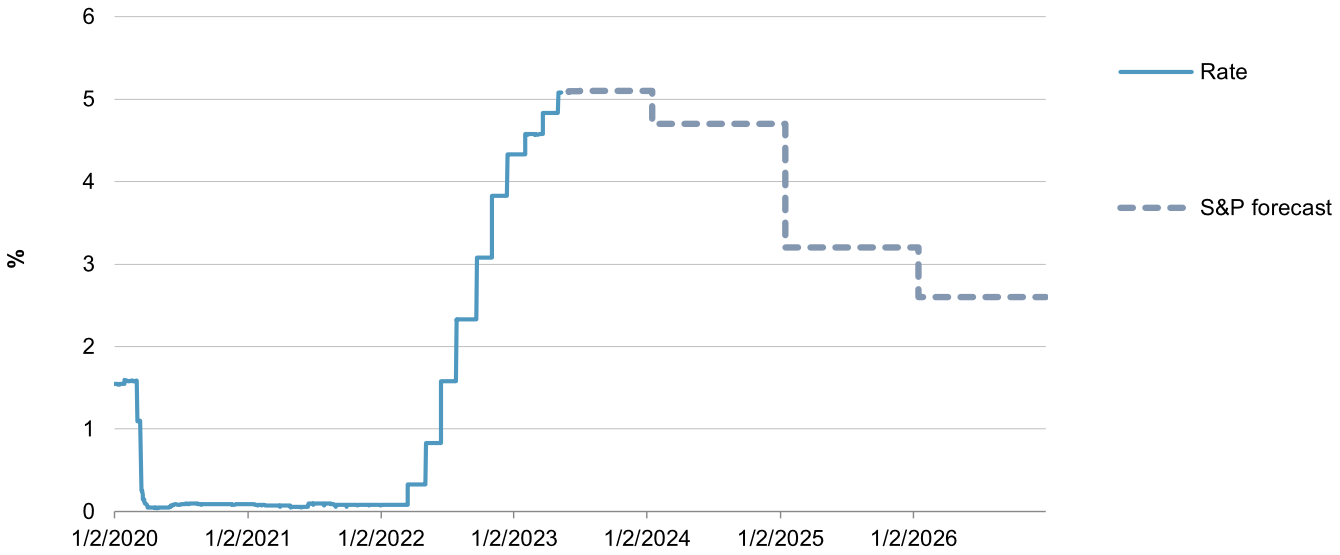
Chart 8

Federal Reserve funds rate



Sources: Federal Reserve Bank of New York; S&P Global Ratings, Economic Outlook U.S. Q2 2023: Still Resilient, Downside Risks Rise.

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We expect that ut t es cap ta spend ng w cont nue to gradua y r se over the next decade as they a ocate funds for safety, re ab ty, energy trans t on programs, and to support e ectr c veh c e n t at ves. We be eve the nf at on Reduct on Act (RA) that prov des for ong term tax cred ts for renewab es, batter es, nuc ear power, and hydrogen, and a ows for the re at ve y easy transferab ty of these tax cred ts, on y supports our v ew that ut t es w step up spend ng over the onger term. A though th s growth s v ta for ut t es to meet the r goa s, f they don t suff c ent y fund t n a cred t support ve manner, the r cred t measures and cred t qua ty cou d dec ne.

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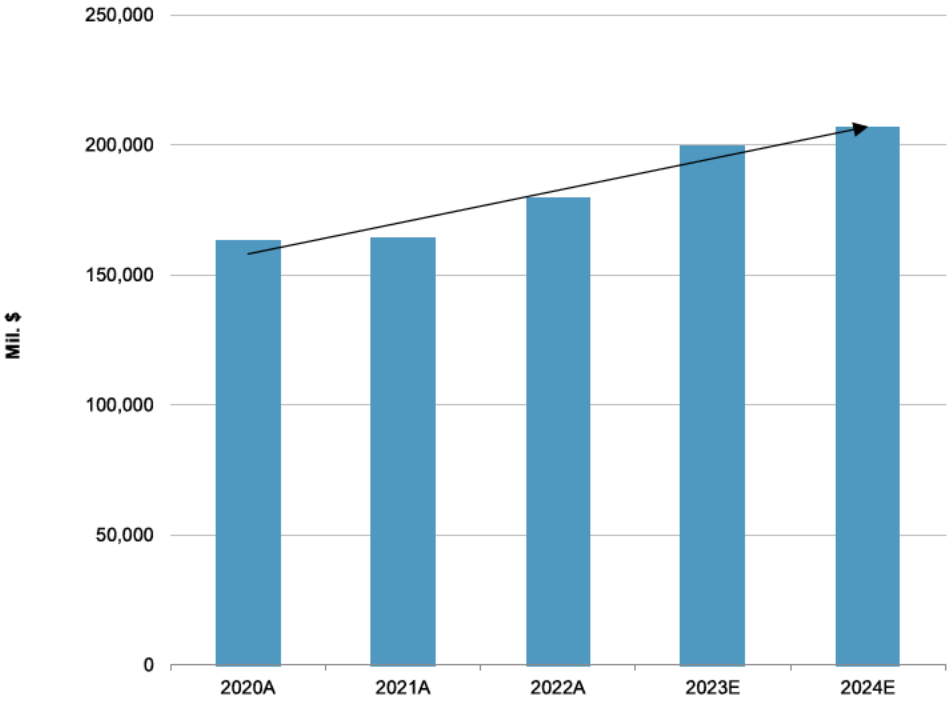
Chart 9

North American regulated utilities' rising capital expenditures



Data as of May 1, 2023. a--Actual. e-- Estimates. Source: S&P Global Ratings.
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About one th rd of the ndustry s strateg ca y manag ng the r f nanc a performance w th on y m n ma f nanc a cush on, ref ect ng funds from operat ons (O) to debt that s ess than 00 bas s po nts above the downgrade thresho d. Because ut ty cash f ows are typ ca y more stab e than those of many other ndustr es, th s strategy of operat ng w th h gher everage works we under ord nary econom c cond t ons. However, when unexpected r sks occur or base case assumpt ons dev ate from expectat ons, the ut ty s cred t qua ty can weaken.

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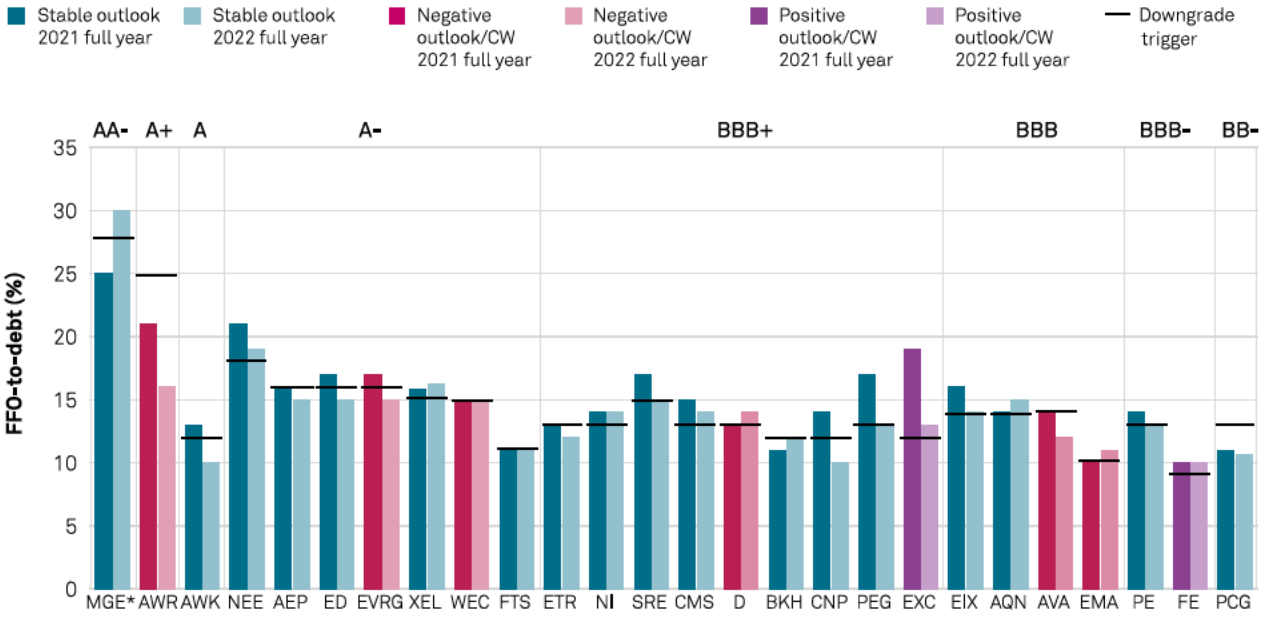
Aug 03 2023

Minimal financial cushion



*MGEE (MGE Energy Inc) is parent company of Madison Gas & Electric, this rating relates to Madison Gas & Electric.)
As of May 15, 2023. Source: S&P Global Ratings.
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A though North Amer can regu ated ut t es are exposed to these r sks, our stab e out ook on the ndustry takes nto account mprov ng econom c cond t ons. We expect that over the next two years ndustry upgrades and downgrades w be more ba anced and cons stent w th the sector s onger term stab e trends.

h s report does not const t te a rat ng act on

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MOODY'S

Rating Action: Moody's affirms Duke Energy and subsidiary ratings; changes outlook of Duke Energy Kentucky to negative

24 Apr 2023

New York, April 24, 2023 -- Moody's Investors Service (Moody's) affirmed the ratings of Duke Energy Corporation (Duke, Baa2) along with the ratings of its utility subsidiaries: Duke Energy Carolinas, LLC (Duke Energy Carolinas, A2), Duke Energy Progress, LLC (Duke Energy Progress, A2), Duke Energy Florida, LLC. (Duke Energy Florida, A3), Duke Energy Indiana, LLC. (Duke Energy Indiana A2), Duke Energy Ohio, Inc. (Duke Energy Ohio, Baa1), Duke Energy Kentucky, Inc. (Duke Energy Kentucky, Baa1), and Piedmont Natural Gas Company, Inc. (Piedmont, A3). Moody's also affirmed the ratings of Duke's intermediate subsidiary holding company, Progress Energy, Inc. (Progress Energy, Baa1).

At the same time, Moody's changed the rating outlook of Duke Energy Kentucky to negative from stable. The rating outlook for Duke and all of its other subsidiaries is stable.

RATINGS RATIONALE

"The ratings affirmation of Duke and its subsidiaries reflects our expectation that continued credit supportive regulation will help the utilities to maintain their credit quality despite substantial capital investment programs" stated Nana Hamilton, VP- Senior Analyst. "Duke Energy Kentucky's negative outlook reflects the potential that historically weak credit metrics will be sustained going forward should the outcome of the company's pending rate case be unfavorable" added Hamilton.

Over the next two years, we expect Duke's ratio of operating cash flow excluding changes in working capital (CFO pre-WC) to debt ratio to be maintained in the 13%-15% range that we have indicated as appropriate for its current Baa2 rating, albeit at the bottom half of that range, leaving it with little financial flexibility. The company's 2022 credit metrics were materially lower than that range, including a ratio of CFO pre-WC to debt of 11.3% (adjusted for securitization and Duke's proportional ownership of Duke Energy Indiana), primarily due to about $3.9 billion in deferred fuel costs. Adjusting for the cash flow impact of these deferred fuel costs, substantially all which we expect to be recovered by the end of 2024, the CFO pre-WC to debt ratio would have been 12.9%.

With no equity issuances in its financing plan and one of the largest capital expenditure programs in the utilities sector, Duke's credit metrics will remain under pressure. However, we expect continued credit supportive regulation, particularly in Duke's largest service territories in North Carolina, Florida and Indiana, to help the company maintain debt coverage metrics within our expected range for the current rating. Duke is also currently pursuing a sale of its commercial renewables business and proceeds from a successful sale would provide additional funds to supplement debt financing.

The ratings affirmation and stable outlooks at Duke Energy Carolinas and Duke Energy Progress consider what we expect will be credit supportive outcomes of currently pending rate cases at both utilities. Despite generally collaborative regulatory relationships, Duke's Carolina utilities, which combined make up approximately 55% of its earnings base, have historically not benefited from

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tracking mechanisms that could serve to reduce regulatory lag on investments. However, pursuant to legislation passed in October 2021, both utilities are requesting multi-year performance based rate plans for the first time in North Carolina which we view as a positive development toward mitigating this regulatory lag. Both utilities' 2022 credit metrics were depressed by significant under-recovered fuel costs with Duke Energy Carolinas requesting a 12 month recovery of these costs effective September 2023 and Duke Energy Progress expected to request 12 month recovery effective December 2023. A final commission order is expected for Duke Energy Carolinas in August 2023. Over the next two years, we expect both utilities to produce a ratio of CFO pre-WC to debt in the 20%-22% range, excluding the financial impact of storm cost securitization.

The affirmation of Duke Energy Florida's ratings recognizes credit supportive regulation in Florida that allows for timely recovery of costs and investments. This is especially important for Duke Energy Florida whose service territory is highly exposed to hurricanes. The relatively quick restoration of power to about one million customers within three days after Hurricane Ian exited the state in October 2022 demonstrates the success of its infrastructure hardening investments. As of 31 December 2022, Duke Energy Florida had about $353 million of deferred Hurricane Ian costs and has received regulatory approval to recover costs associated with Ian over 12 months and to replenish its storm reserve. Duke Energy Florida's 2022 credit metrics were negatively impacted by the higher debt incurred to fund storm costs and high fuel costs. Over the next two years, we expect the utility will be able to maintain a ratio of CFO pre-WC to debt of around 20%, excluding the financial impact of securitization bonds associated with the retirement of its Crystal River nuclear plant.

The affirmation of intermediate parent company Progress Energy's rating is driven by the affirmation of the ratings of subsidiaries Duke Energy Progress and Duke Energy Florida. The Baa1 rating reflects the structurally subordinate position of its debt vis-à-vis the debt at these two subsidiaries. The percentage of intermediate parent level debt as compared to total consolidated Progress Energy debt has decreased significantly over time and at year-end 2022 was approximately 7%, down from 20% in 2021. This is due to a $450 million maturity in 2022 and higher debt at its subsidiaries to fund higher fuel costs and storm costs. Excluding securitization bonds and associated cash flow impacts, we expect Progress Energy to generate a ratio of CFO pre-WC to debt in the high teens over the next two years.

The affirmation of Duke Energy Indiana's rating acknowledges credit supportive regulation in Indiana including forward looking test years for rate cases and several authorized rider/tracker provisions that permit timely recovery of expenditures. Duke closed the second phase of its minority sale of Duke Energy Indiana to GIC in December 2022, with Duke Energy Indiana issuing an additional 8.85% of its membership interests in exchange for approximately $1 billion, following a sale of 11.05% of its membership interests in September 2021. Our assessment of Duke's credit quality proportionally consolidates the 80.1% of Duke Energy Indiana that it now owns.

We expect Duke Energy Indiana to produce credit metrics in line with our expectations for its rating over the next two years, including a ratio of CFO pre-WC to debt in the low 20% range. However, credit metrics will be pressured beyond 2025 when capital expenditures are forecast to significantly increase to about $1.5 billion annually, up from an already high annual average of around $900 million. The utility's transition away from coal, which represents about 70% of its generation portfolio, is the primary driver of the increase in capital spending. Despite timely cost recovery mechanisms, the sheer size of its capital expenditure program will increase regulatory lag and require more frequent rate case activity.

Duke Energy Ohio's Baa1 rating affirmation reflects a credit supportive regulatory environment that includes a large number of riders and trackers for investments in the company's transmission and distribution system. Credit metrics have been at the weak end of our expectation for the rating over

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the last three years, including a ratio of CFO pre-WC to debt averaging 15.1%, as the utility has continued to make significant investments in transmission and distribution. With a recently approved electric rate increase effective January 2023 and a pending natural gas rate case, we expect Duke Energy Ohio to maintain a ratio of CFO pre-WC to debt in the 15% - 17% range over the next two years. Longer-term, Duke Energy Ohio's next electric security plan (ESP), which will be effective in 2026, will be important to its future credit quality.

The negative outlook on Duke Energy Kentucky reflects a history of weak credit metrics, including a CFO pre-WC to debt averaging 15.2% in recent years, consistently below our minimum expectation of 17% for its Baa1 rating. These weak metrics may persist depending on the outcome of its currently pending electric rate case. Although Duke Energy Kentucky benefits from several cost recovery mechanisms, including recovery of fuel, purchased power, and environmental compliance costs and the use of a forward test year in rate cases, the company's cash flow has been flat since 2018 relative to a compound annual growth rate in debt of about 10%. In its electric rate case, Duke Energy Kentucky has requested a revenue increase of $75 million based on a 10.35% return on equity and a 52.51% equity layer. A final decision is expected by the end of the second quarter of 2023 and will be important to our assessment of the company's Baa1 credit rating.

The affirmation of Piedmont's A3 rating reflects its low business risk as a regulated natural gas local distribution company operating in supportive regulatory jurisdictions in North Carolina, South Carolina and Tennessee. Substantial capital expenditures, averaging about $870 million annually over the last three years, have kept pressure on debt coverage metrics, with an average CFO pre-WC to debt ratio of 14.3%. Piedmont has not paid a dividend to Duke since 2016, which has helped to support the utility's credit profile through a period of high capital expenditures. The company forecasts annual capital expenditures to be in the $900 million to $950 million range over the next two years as it continues to invest in infrastructure to support customer growth and system integrity. We expect credit metrics to remain pressured over the next two years, with a ratio of CFO pre-WC to debt in the 15%-16% range but see improving debt coverage metrics beyond 2024 when the utility's capital spending is forecast to moderate to a range of $600 million to $700 million annually.

Rating Outlook

The stable outlook for Duke and its subsidiaries, with the exception of Duke Energy Kentucky, reflects our expectation that the companies will maintain supportive regulatory relationships in all of their 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.

FACTORS THAT COULD LEAD TO AN UPGRADE OR DOWNGRADE OF THE RATINGS

Factors that ould Lead to an Upgrade

While unlikely in the near term, upward pressure on the ratings could develop if regulatory environments were to become more supportive, resulting in increased cash flow, or if there were to be reductions in leverage leading to materially stronger credit metrics.

For example, at Duke, an upgrade could be considered if it exhibits a consolidated ratio of CFO pre-WC to debt above 15% on a sustainable basis; at Duke Energy Carolinas, Duke Energy Progress and Duke Energy Indiana, a ratio above 25%; at Duke Energy Florida, a ratio above 22%; at Duke Energy Ohio, a ratio at or above 19% (down from 20% previously); and at Duke Energy Kentucky a ratio above 21% (down from 22% previously). An upgrade of Duke Energy Progress or Duke Energy Florida could put upward pressure on the rating of Progress Energy. At Piedmont, a ratio of CFO pre-

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WC to debt above 19% (up from 18% previously) could put upward pressure on the rating.

Factors that Could Lead to a Downgrade

Downward rating action could be considered if there were to be a deterioration in the credit supportiveness of the regulatory relationships at Duke's subsidiaries, that could result in a reduction in cash flow. A material increase in operating or capital expenditures that is not able to be recovered on a timely basis, or an increase in leverage leading to weaker credit metrics could also put downward pressure on the ratings.

For example, at Duke, a downgrade could be considered if the consolidated ratio of CFO pre-WC to debt sustained below 13%; at Duke Energy Carolinas and Duke Energy Progress a ratio maintained below 21% (up from 20% previously); at Duke Energy Indiana a ratio maintained below 22%; at Duke Energy Florida a ratio below 19%; at Duke Energy Ohio a ratio below 15%; and at Duke Energy Kentucky a ratio below 17%. A downgrade of Duke Energy Progress or Duke Energy Florida could put downward pressure on the rating of Progress Energy. At Piedmont, a ratio of CFO pre-WC to debt below 15% (up from 14% previously) could put downward pressure on the rating.

Headquartered in Charlotte, North Carolina, Duke is a large energy holding company with mostly regulated utility operations. Its main business consists of its electric utilities and infrastructure business segment, which serves approximately 8.2 million retail electric customers in six US states and made up about 90% of Duke's 2021 earnings base. Duke's gas utilities and infrastructure businesses provide natural gas to approximately 1.6 million customers located in five states.

Affirmations:

..Issuer: Duke Energy Corporation

.... Issuer Rating, Affirmed Baa2

....Senior Unsecured Conv./Exch. Bond/Debenture, Affirmed Baa2

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa2

....Senior Unsecured Shelf, Affirmed (P)Baa2

....Junior Subordinated Regular Bond/Debenture, Affirmed Baa3

....Pref. Stock Preferred Stock, Affirmed Ba1

....Pref. Shelf, Affirmed (P)Ba1

....Senior Unsecured Bank Credit Facility, Affirmed Baa2

....Senior Unsecured Commercial Paper, Affirmed P-2

..Issuer: Duke Energy Indiana, LLC.

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

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....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Underlying Senior Secured First Mortgage Bonds, Affirmed Aa3

....Backed Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Regular Bond/Debenture, Affirmed Aa3

....Senior Secured Shelf, Affirmed (P)Aa3

..Issuer: Duke Energy Ohio, Inc.

.... Issuer Rating, Affirmed Baa1

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

....Senior Unsecured Shelf, Affirmed (P)Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Secured Shelf, Affirmed (P)A2

..Issuer: Duke Energy Kentucky, Inc.

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Duke Energy Carolinas, LLC

.... Issuer Rating, Affirmed A2

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Shelf, Affirmed (P)Aa3

..Issuer: Piedmont Natural Gas Company, Inc.

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

..Issuer: Progress Energy, Inc.

....Senior Unsecured Regular Bond/Debenture, Affirmed Baa1

..Issuer: Duke Energy Progress, LLC

.... Issuer Rating, Affirmed A2

....Senior Unsecured Shelf, Affirmed (P)A2

....Senior Secured First Mortgage Bonds, Affirmed Aa3

....Senior Secured Shelf, Affirmed (P)Aa3

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..Issuer: Duke Energy Florida, LLC.

.... Issuer Rating, Affirmed A3

....Senior Unsecured Regular Bond/Debenture, Affirmed A3

....Underlying Senior Unsecured Regular Bond/Debenture, Affirmed A3

....Backed Senior Unsecured Regular Bond/Debenture, Affirmed A3

....Senior Unsecured Shelf, Affirmed (P)A3

....Senior Secured First Mortgage Bonds, Affirmed A1

....Underlying Senior Secured First Mortgage Bonds, Affirmed A1

....Backed Senior Secured First Mortgage Bonds, Affirmed A1

....Senior Secured Shelf, Affirmed (P)A1

..Issuer: Boone (County of) KY

....Senior Unsecured Revenue Bonds, Affirmed Baa1

....Underlying Senior Unsecured Revenue Bonds, Affirmed Baa1

....Backed Senior Unsecured Revenue Bonds, Affirmed Baa1

..Issuer: CITRUS (COUNTY OF) FL

....Underlying Senior Secured Revenue Bonds, Affirmed A1

....Backed Senior Secured Revenue Bonds, Affirmed A1

..Issuer: Indiana Finance Authority

....Senior Secured Revenue Bonds, Affirmed Aa3

....Senior Unsecured Revenue Bonds, Affirmed A2

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

....Backed Senior Unsecured Revenue Bonds, Affirmed A2

....Senior Unsecured Revenue Bonds, Affirmed VMIG 1

..Issuer: North Carolina Capital Facilities Fin. Agy.

....Backed Senior Secured Revenue Bonds, Affirmed Aa3

....Underlying Senior Unsecured Revenue Bonds, Affirmed A2

....Backed Senior Unsecured Revenue Bonds, Affirmed A2

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..Issuer: Ohio Air Quality Development Authority

....Senior Unsecured Revenue Bonds, Affirmed Baa1

....Underlying Senior Unsecured Revenue Bonds, Affirmed Baa1

....Backed Unsecured Revenue Bonds, Affirmed Baa1

..Issuer: Ohio Water Development Authority

....Underlying Unsecured Revenue Bonds, Affirmed Baa1

....Backed Senior Unsecured Revenue Bonds, Affirmed Baa1

..Issuer: Public Finance Authority

....Backed Senior Secured Revenue Bonds, Affirmed Aa3

..Issuer: Wake County I.F. & P.C.F.A., NC (The)

....Underlying Senior Secured Revenue Bonds, Affirmed Aa3

....Backed Senior Secured Revenue Bonds, Affirmed Aa3

Outlook Actions:

..Issuer: Duke Energy Corporation

....Outlook, Remains Stable

..Issuer: Duke Energy Indiana, LLC.

....Outlook, Remains Stable

..Issuer: Duke Energy Ohio, Inc.

....Outlook, Remains Stable

..Issuer: Duke Energy Kentucky, Inc.

....Outlook, Changed To Negative From Stable

..Issuer: Duke Energy Carolinas, LLC

....Outlook, Remains Stable

..Issuer: Piedmont Natural Gas Company, Inc.

....Outlook, Remains Stable

..Issuer: Progress Energy, Inc.

....Outlook, Remains Stable

..Issuer: Duke Energy Progress, LLC

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....Outlook, Remains Stable

..Issuer: Duke Energy Florida, LLC.

....Outlook, Remains Stable

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017 and available at https://ratings.moodys.com/api/rmc-documents/68547. Alternatively, please see the Rating Methodologies page on https://ratings.moodys.com for a copy of this methodology.

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CREDIT OPINION
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Update

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RATINGS

Duke Energy Carolinas, LLC

Domicile	Charlotte, 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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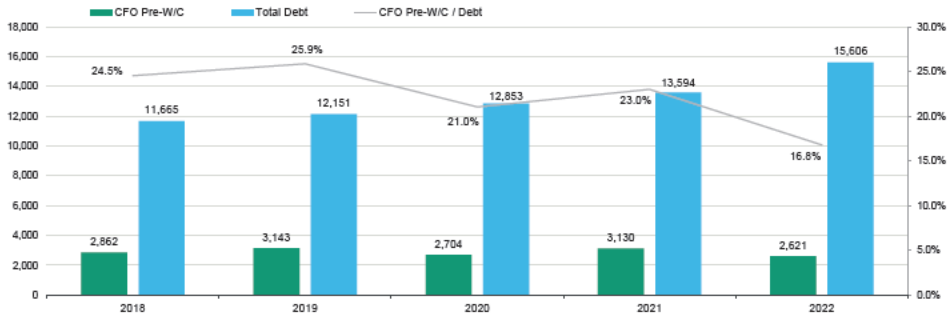
Duke Energy Carolinas, LLC

Update to credit analysis

Summary

Duke Energy Carolinas' (Duke Carolinas) credit reflects its low business and operating risk profile and supportive regulatory environments in both North and South Carolina. Our view also considers the company's position as the largest subsidiary within the Duke Energy Corporation (Duke, Baa2 stable) family, making up about a third of its rate base. North Carolina's House Bill (HB) 951, signed into law in October 2021 to guide the states clean energy transition, will be an important driver of the company's credit quality going forward. Over the next two years, we expect Duke Carolinas to maintain credit metrics that are supportive of its current A2 credit rating, including a ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt sustained in the low 20% range.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($ MM)



Note: The 2022 CFO pre-WC to debt ratio, excluding the financial impact of storm cost securitization and the cash flow impact of deferred fuel costs which we expect to be recovered by the end of 2024, would have been 21.3%, see Exhibit 3 for details.
Source: Moody's Financial Metrics™

Credit Strengths

» Credit supportive regulatory environments

» New multiyear performance based ratemaking (PBR) framework in North Carolina could reduce regulatory lag

» Growing service territories

Credit Challenges

» Weakened financial metrics

» Regulatory lag due to lack of rider/tracker mechanisms for cost recovery

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» High capital expenditures

» Storm prone service territory

Rating Outlook

The stable outlook recognizes Duke Carolinas' supportive regulatory relationships in North and South Carolina and an improving regulatory framework in North Carolina. The stable outlook assumes that the utility will recover its prudently incurred costs in a relatively timely manner, and that the company will fund its significant capital program in a manner that supports its balance sheet. The stable outlook further assumes that Duke Carolinas will demonstrate credit metrics that are supportive of its credit rating, including a ratio of cash flow from operations excluding changes in working capital (CFO pre-WC) to debt in the low 20% range.

Factors that Could Lead to an Upgrade

» Credit positive changes in the utility's regulatory framework, including more riders and trackers to reduce regulatory lag and improve cash flow.

» Increased cash flow, or a reduction in leverage, enabling the company to maintain a ratio of CFO pre-WC to debt of around 25% or above.

Factors that Could Lead to a Downgrade

» A decline in the credit supportiveness of Duke Carolinas' regulatory relationships in North or South Carolina.

» Additional capital expenditures or other capital needs that result in a material increase in debt levels or are not recoverable.

» A ratio of CFO pre-WC to debt, excluding the financial effects of storm cost securitization, remaining below 21% on a sustained basis.

Key Indicators

Exhibit 2

Duke Energy Carolinas, LLC [1]

	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22
CFO Pre-W/C + Interest / Interest	6.9x	7.3x	6.2x	6.5x	5.3x
CFO Pre-W/C / Debt	24.5%	25.9%	21.0%	23.0%	16.8%
CFO Pre-W/C – Dividends / Debt	18.1%	23.6%	16.4%	18.6%	16.5%
Debt / Capitalization	43.3%	42.2%	43.1%	43.7%	44.4%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Note: The 2022 CFO pre-WC to debt ratio, excluding the financial impact of storm cost securitization and the cash flow impact of deferred fuel costs which we expect to be recovered by the end of 2024, would have been 21.3%, see Exhibit 3 for details.
Source: Moody's Financial Metrics™

Profile

Duke Carolinas is a vertically integrated electric utility serving approximately 2.8 million customers in North Carolina (about 2 million) and South Carolina. The utility is the largest subsidiary of Duke and is regulated by the North Carolina Utilities Commission (NCUC) and the Public Service Commission of South Carolina (PSCSC).

Detailed Credit Considerations

Credit supportive regulatory environments

The regulatory environments in both North and South Carolina have historically been credit supportive with regard to rate decisions, ultimate recovery of prudently incurred costs, authorized returns and equity layers. Utilities have been able to reach settlement agreements on traditional rate making parameters, which we view positively, leaving only more contentious items, such as the recovery

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of coal ash remediation spending, to be fully litigated. In January 2021, Duke Carolinas reached a settlement agreement in North Carolina with key intervenors resolving all prior issues regarding coal ash and establishing a framework for future recovery.

Despite this generally collaborative environment, utilities in North and South Carolina do not benefit from tracking mechanisms that could serve to reduce regulatory lag on investment in their systems or to speed the recovery of coal ash remediation spending. However, North Carolina's new performance-based ratemaking (PBR) framework, as authorized in HB 951, is a positive development towards mitigating regulatory lag.

North Carolina – HB 951, signed into law in October 2021, directs the North Carolina Utilities Commission (NCUC), in collaboration with the state's utilities and other stakeholders, to develop a plan to reduce carbon emissions by 70% by 2030 relative to 2005 levels and achieve carbon neutrality by 2050 via the least cost means, while maintaining reliability. It also allows Duke's North Carolina utilities to own and rate base 55% of commission approved new solar generation facilities and fully rate base all other approved new sources of generation. For early subcritical coal power plant retirements, the law allows for the securitization of 50% of the remaining net book value. In addition, the law authorizes the NCUC to consider multiyear rate plans (MYRP) and PBR as well as revenue decoupling, a mechanism we view as credit positive, for residential customers.

Pursuant to HB 951, Duke Carolinas filed its first PBR application with the NCUC in January 2023, requesting recovery of forecast capital expenditures over a three-year MYRP period. The company requested an $823 million revenue increase over three years, including a $501 million increase for the first year effective 1 January 2024, $172 million for the second year and $150 million for the third year. The request is based on a 10.4% ROE and 53% equity layer. The PBR application includes an earnings sharing mechanism, a residential decoupling mechanism and performance based incentives as authorized under HB 951. Duke Carolinas requested that interim rates be made effective on 1 September 2023.

In January 2021, Duke announced a settlement agreement with the North Carolina Attorney General's Office, the Public Staff and the Sierra Club that resolved all issues surrounding historical coal ash remediation prudence and cost recovery in the state. The settlement, approved in March 2021, affirmed the cost recovery provisions for coal ash spending that were approved in the NCUC's 2018 rate decision, which included a five year amortization period with a full debt and equity return. Duke Carolinas was also authorized to recover approved coal ash costs in its 2019 rate case over five years and earn a debt and equity return on the deferred balance; however the equity rate earned during the amortization period was set 150 basis points below the 9.6% ROE approved in the 2019 rate case.

The coal ash settlement also limits the scope of future rate proceedings and establishes that, through 2030, the company will continue to be able to earn a debt and equity return for coal ash remediation spending, with the equity rate set at 150 basis points below the prevailing ROE. As part of the settlement, Duke Carolinas agreed not to seek recovery of a portion of its deferred coal ash expenditures and, as a result, the company recorded an estimated $454 million pre-tax impairment charge and refunded approximately $50 million of previously collected wholesale revenues. This represents a sharing of costs with shareholders and was a provision sought by parties to the settlement.

In May 2021, the NCUC approved the securitization of deferred storm costs at Duke Carolinas and issued an order allowing the company to issue storm recovery bonds to recover $237 million of storm costs, including carrying and financing costs, over a period of 20 years. The bonds were issued in November 2021.

South Carolina - (approximately 25% of rate base) The PSCSC's May 2019 order in Duke Carolinas' most recent rate case denied recovery of the majority of the company's incremental South Carolina allocated spending on coal ash remediation because the incremental costs were a result of North Carolina's coal ash law. However, the balance of the order (which included an approved 53% equity ratio) was generally credit supportive. The company appealed the coal ash disallowance to the Supreme Court of South Carolina. On 27 October 2021, the Supreme Court affirmed the PSCSC's May 2019 order disallowing recovery of certain CCR compliance and coal ash insurance litigation costs. Consequently, Duke Carolinas recognized approximately $160 million of impairment charges and a $31 million increase in other income for fiscal year 2021. In February 2022, the South Carolina Supreme Court denied a petition for rehearing, filed by Duke Carolinas in November 2021, on several issues including the decision on coal ash cost recovery.

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On a more positive note, the South Carolina order continued authorization of the utility's ability to earn a full weighted average cost of capital return on its previously approved coal ash remediation spending. The order also shortened the recovery period to five years, versus a previously approved fifteen years.

Financial metrics expected to recover and remain supportive of the current credit rating

Duke Carolinas' historically strong financial coverage metrics have declined materially in recent years, including a ratio of CFO pre-WC to debt falling from 25% in 2018 and 2019 to around 22% in 2020 and 2021 and 17% in 2023. Drivers of this decline have included spending for coal ash remediation, new generation and grid modernization, as well as the negative cash flow impact of tax reform, the coronavirus pandemic and unusually severe storms.

Going forward, we expect the company's credit metrics to recover from the low levels exhibited in 2023, with CFO pre-WC to debt returning the low 20% range. Nevertheless, recovery of ongoing coal ash remediation spending (which still must be recovered via general base rate case proceedings) and elevated spending for grid modernization and generation transition investments will continue to maintain pressure on credit metrics. Our analysis focuses on financial metrics that exclude the impacts of storm cost securitization debt because Duke Carolinas simply acts as a conduit for the repayment of a customer obligation as mandated by law.

The company's 2022 credit metrics were particularly weak, including a ratio of CFO pre-WC/debt of 17% when adjusted for securitization, primarily due to significant deferred fuel costs. After adjusting for the cash flow impact of deferred fuel costs, substantially all which we expect to be recovered by the end of 2024, the CFO pre-WC to debt ratio would have been 21.3% as shown below. Duke Carolinas has filed for recovery of these fuel costs over a 12 month period effective September 2023. A final commission order is expected in August 2023.

Exhibit 3

Duke Carolinas adjusted 2022 CFO pre-WC to debt detail

	2022
Cash flow from operations (GAAP)	1,569
Exclude changes in current assets/liabilites (working capital)	867
Unadjusted CFO pre-WC	2,436
Primary adjustments	
Lease	35
Capitalized Interest	(50)
ARO (Coal Ash)	200
Other analyst adjustments	
Securitiza ion	(12)
LT deferred fuel costs	668
Preliminary adjusted CFO pre-WC (excl. other analyst adjustments)	**2,621**
Fully adjusted CFO pre-WC (incl. other analyst adjustments)	**3,277**
Debt (GAAP)	15,499
Primary adjustments	
Pension	10
Lease	97
Other analyst adjustments	
Securitiza ion	(228)
Preliminary adjusted debt (excluding other analyst adjustments)	**15,606**
Fully adjusted debt (including other analyst adjustments)	**15,378**
Preliminary adjusted CFO pre-WC/debt	**16.8%**
Fully adjusted CFO pre-WC/debt	**21.3%**

Source: Moody's Investors Service, Company

Our analysis of Duke Carolinas credit includes the impact of its current settlement agreements in North Carolina. Our calculation of Duke Carolinas' credit metrics reflects our treatment of coal ash remediation expenditures as akin to a capital investment rather than an operating expense. We have taken this view in light of the fact that the company has been allowed to earn a debt and equity return

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on its approved deferral balances. Although the settlement incorporates a discount to the equity return, bringing it to 150 basis points below the prevailing ROE, we recognize that regulatory commissions have the discretion to establish different ROEs for particular investments, or for use in various riders.

Capital expenditures to remain elevated

Capital expenditures (inclusive of coal ash remediation spending) at Duke Carolinas have been on the rise, and were $3.5 billion in 2022, up from $2.9 billion in 2021. Going forward, the company's current five year capital plan includes average annual spending of about $4.1 billion, as it spends more for electric distribution, new generation and grid modernization investments in transmission.

Pursuant to the HB 951 requirement that the NCUC develop, together with the state's utilities, a plan to reduce carbon emissions by 70% by 2030 and achieve carbon neutrality by 2050, Duke Carolinas and sister company Duke Energy Progress, LLC (A2 stable) filed an initial carbon plan with the NCUC in May 2022. In December 2022, the NCUC issued an order adopting an initial carbon plan, with near-term procurement and development action items. North Carolina's carbon reduction plan will drive a substantial portion of Duke and its Carolina utilities' capital expenditures going forward.

Although HB 951 is North Carolina legislation, we expect Duke Carolinas to also work with regulators in South Carolina to achieve its carbon reduction goals without cost recovery disallowances as occurred with coal ash cost recovery in the company's 2019 South Carolina rate case order.

Ongoing coal ash remediation

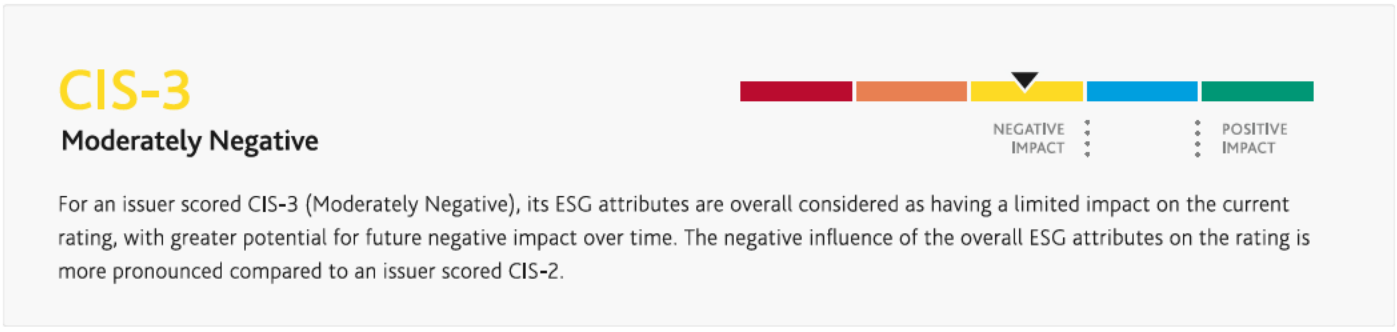
Duke has continued to refine its estimates of coal ash remediation spending since it first recognized an asset retirement obligation in 2014. In December 2019, the company reached an agreement with the North Carolina Department of Environmental Quality (NCDEQ) establishing the means and time frames for remediation of its remaining coal ash basins. The settlement calls for the full excavation of the majority of the ash over a period of 15-20 years. As of 31 December 2022, Duke Carolinas' total remaining coal ash related asset retirement obligation was estimated at about $2.3 billion. Payments for coal ash related asset retirement obligations were $182 million in 2021 and $200 million in 2022. Going forward, the company forecasts environmental spending, inclusive of coal ash remediation, to be at a level of around $200-$275 million per year.

Duke Carolinas' 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.

ESG considerations

Duke Carolinas' ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 4
ESG Credit Impact Score



Source: Moody's Investors Service

Duke Carolinas' ESG Credit Impact Score is moderately negative (**CIS-3**), where its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. Duke Carolinas' **CIS-3** reflects highly negative environmental risk, moderately negative social risk and neutral to low governance risk.

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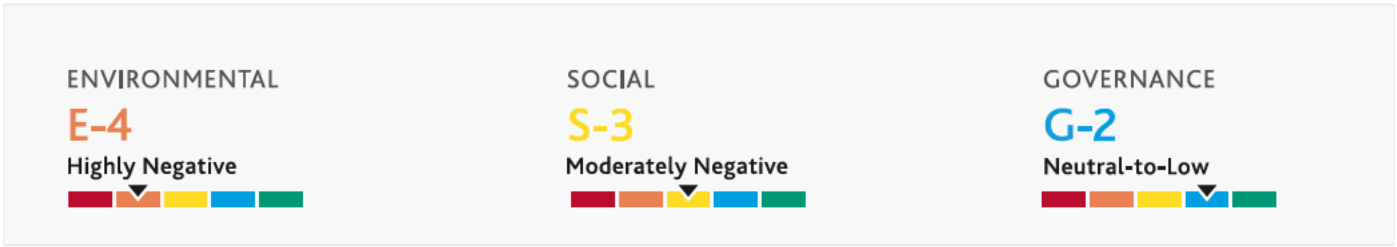
Exhibit 5
ESG Issuer Profile Scores



Source: Moody's Investors Service

Environmental

Duke Carolinas' highly negative exposure to environmental risk (**E-4** issuer profile score) reflects the vulnerability of its service territory to hurricanes and tropical storms which can cause costly damage to physical assets. The company's fossil fuel generation fleet presents moderate exposure to carbon transition risk, and its coal and nuclear fleets also expose the company to moderate risks of waste management and pollution. Risks associated with water management and natural capital are neutral to the company's credit profile.

Social

Duke Carolinas' exposure to social risks is moderately negative (**S-3** issuer profile score) because the operation of nuclear facilities heightens the risk of responsible production, while demographics and societal trends that increase public concern over environmental, social, or affordability issues could lead to adverse regulatory or political intervention. Risks related to customer relations, employee health and safety and human capital are neutral to the company's credit profile.

Governance

Duke Carolinas' **G-2** governance issuer profile score is driven by that of its parent Duke. Duke's governance (**G-2** issuer profile score) is broadly in line with other utilities and does not pose a particular risk. Duke Carolinas' governance profile is supported by neutral to low risks associated with financial strategy and risk management, management credibility and track record, organizational structure, compliance and reporting and board structure policies and procedures.

ESG Issuer Profile Scores and Credit Impact Scores for Duke Carolinas are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for Duke Carolinas on Moodys.com and view the ESG Scores section.

Liquidity Analysis

We expect Duke Carolinas to maintain adequate liquidity. For the year ended 31 December 2022, Duke Carolinas generated approximately $1.6 billion of cash from operations (CFO), invested approximately $3.3 billion in capital expenditures (excluding coal ash remediation spending) and upstreamed $50 million in dividend payments to parent Duke, resulting in negative free cash flow (FCF) of about $1.8 billion. Going forward, we expect Duke Carolinas to remain cash flow negative with cash shortfalls funded via a combination of internal and external sources.

Duke Carolinas' liquidity sources include access to funding from Duke's commercial paper program through the Duke system money pool, and direct borrowings from the money pool. As of 31 December 2022, the utility had $1.925 billion of borrowing capacity under Duke's $9 billion master credit facility. As of 31 December 2022, the utility had around $1.5 billion of commercial paper outstanding, and $4 million of letters of credit outstanding, reducing its available capacity under the parent master credit facility to approximately $388 million.

Duke's master credit facility terminates in March 2028. 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 Natural Gas Company (Piedmont). The debt to capitalization covenant for Piedmont is a maximum of 70%. As of 31 December 2022, Duke reported that all entities were in compliance with the covenant and we estimate Duke Carolinas' ratio was about 50%.

Duke Carolinas' nearest long-term debt maturity is $471 million of account receivable securitization debt due in January 2025.

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Rating Methodology and Scorecard Factors

Exhibit 6

Methodology Scorecard Factors

Duke Energy Carolinas, LLC

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current FY 12/31/2022		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	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.0x	A	5.5x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	20.1%	Baa	20% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	17.1%	A	15% - 20%	A
d) Debt / Capitalization (3 Year Avg)	43.8%	A	40% - 45%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching		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 12/31/2022
[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™

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Appendix

Exhibit 7

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22
As Adjusted					
FFO	**3,129**	**3,230**	**2,857**	**2,993**	**3,421**
+/- Other	-267	-87	-153	137	-800
CFO Pre-WC	**2,862**	**3,143**	**2,704**	**3,130**	**2,621**
+/- ΔWC	-96	-144	255	-233	-867
CFO	**2,766**	**2,999**	**2,959**	**2,897**	**1,754**
- Div	750	275	600	600	50
- Capex	2,942	3,010	2,860	2,891	3,495
FCF	**-926**	**-286**	**-501**	**-594**	**-1,791**
(CFO Pre-W/C) / Debt	24.5%	25.9%	21.0%	23.0%	16.8%
(CFO Pre-W/C - Dividends) / Debt	18.1%	23.6%	16.4%	18.6%	16.5%
FFO / Debt	26.8%	26.6%	22.2%	22.0%	21.9%
RCF / Debt	20.4%	24.3%	17.6%	17.6%	21.6%
Revenue	7,300	7,395	7,015	7,102	7,857
Interest Expense	482	498	519	571	611
Net Income	1,025	1,348	1,267	1,442	1,504
Total Assets	40,121	44,023	45,020	47,133	50,296
Total Liabilities	28,542	31,315	31,888	33,265	34,894
Total Equity	11,579	12,708	13,132	13,868	15,403

[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 8

Peer Comparison Table [1]

	Duke Energy Carolinas, LLC A2 (Stable)			Duke Energy Progress, LLC A2 (Stable)			Virginia Electric and Power Company A2 (Stable)			Alabama Power Company A1 (Stable)		
(In US millions)	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-20	FYE Dec-21	FYE Dec-22
Revenue	7,015	7,102	7,857	5,422	5,780	6,753	7,763	7,470	9,654	5,830	6,413	7,817
CFO Pre-W/C	2,704	3,130	2,621	1,798	2,240	2,061	2,960	3,374	3,543	2,276	2,287	2,202
Total Debt	12,853	13,594	15,606	9,940	10,852	12,253	15,022	16,061	19,528	9,257	9,957	10,711
CFO Pre-W/C + Interest / Interest	6.2x	6.5x	5.3x	7.3x	8.0x	6.0x	5.8x	6.0x	5.7x	7.5x	7.4x	6.7x
CFO Pre-W/C / Debt	21.0%	23.0%	16.8%	18.1%	20.6%	16.8%	19.7%	21.0%	18.1%	24.6%	23.0%	20.6%
CFO Pre-W/C – Dividends / Debt	16.4%	18.6%	16.5%	14.1%	14.2%	14.8%	16.8%	19.1%	18.1%	14.3%	13.2%	11.1%
Debt / Capitalization	43.1%	43.7%	44.4%	46.2%	48.0%	49.0%	46.5%	45.7%	48.7%	41.0%	40.8%	40.6%

[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™

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Ratings

Exhibit 9

Category	Moody's Rating
DUKE ENERGY CAROLINAS, LLC	
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	Aa3
Senior Secured Shelf	(P)Aa3
Senior Unsecured	A2
PARENT: DUKE ENERGY CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Pref. Stock	Ba1
Commercial Paper	P-2

Source: Moody's Investors Service

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REPORT NUMBER 1362512

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NCUC Form E.S.-1 (modified to exclude current maturities of long-term debt)
Capital
Duke Energy Carolinas, LLC
Twelve Months Ended March 31, 2023

N.C. Rate Base Method
Schedule 2
($000s)

Line No.	Item	Long-term Debt* (a)	Current Maturities of Long-term Debt (b)	Long-term Debt excluding Current Maturities (c)	Preferred Stock (d)	Total Members' Equity (e)	Total Capital (col. c+d+e) (f)	Monthly Common Equity Ratio (col. e/f) (g)
1	Total Company							
2	Balance at end of:							
3	Mar 2022	14,306,563	1,350,000	$ 12,956,563	$ -	14,189,403	$ 27,145,966	52.27%
4	Apr 2022	14,296,365	1,350,000	12,946,365	-	14,252,144	27,198,509	52.40%
5	May 2022	13,949,094	1,000,000	12,949,094	-	14,382,691	27,331,785	52.62%
6	Jun 2022	13,996,344	1,000,000	12,996,344	-	14,529,634	27,525,978	52.79%
7	Jul 2022	14,017,999	1,000,000	13,017,999	-	14,757,945	27,775,944	53.13%
8	Aug 2022	14,057,426	1,000,000	13,057,426	-	14,936,389	27,993,815	53.36%
9	Sep 2022	14,059,367	1,000,000	13,059,367	-	15,112,119	28,171,486	53.64%
10	Oct 2022	14,079,837	1,000,000	13,079,837	-	15,214,505	28,294,342	53.77%
11	Nov 2022	14,056,986	1,000,000	13,056,986	-	15,292,203	28,349,189	53.94%
12	Dec 2022	14,102,625	1,000,000	13,102,625	-	15,439,746	28,542,371	54.09%
13	Jan 2023	15,926,869	1,000,000	14,926,869	-	15,552,437	30,479,306	51.03%
14	Feb 2023	15,945,139	1,000,000	14,945,139	-	15,613,161	30,558,299	51.09%
15	Mar 2023	14,957,589		14,957,589	-	15,734,338	30,691,926	51.27%
16	Total (Sum L3 through L15)	$ 187,752,202		$ 175,052,202	$ -	$ 195,006,714	$ 370,058,917	
17	13 Month Average (L16 / 13 Months)	$ 14,442,477		$ 13,465,554	$ -	$ 15,000,516	$ 28,466,070	
18	13 Month Average Ratio			47.30%	0.00%	52.70%	100.00%	

*Long-term Debt includes Current Maturities

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Rate Case History (Past Rate Cases)

List: None
Company List: All
States: All
Years: 2023, 2022, 2021
Service Type: All

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Increase Authorized			
						Date	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)
Arkansas	Entergy Arkansas LLC	ETR	D-16-036-FR (2022 review)	Electric	Vertically Integrated	7/7/2022	5.25	NA	37.77
Arkansas	Entergy Arkansas LLC	ETR	D-16-036-FR (2021 review)	Electric	Vertically Integrated	7/7/2021	5.17	9.65	37.75
Arkansas	Oklahoma Gas and Electric Co.	OGE	D-18-046-FR (2022 update)	Electric	Vertically Integrated	10/3/2022	5.33	NA	38.57
Arkansas	Oklahoma Gas and Electric Co.	OGE	D-18-046-FR (2021 update)	Electric	Vertically Integrated	10/1/2021	5.23	NA	37.95
Arkansas	Oklahoma Gas and Electric Co.	OGE	D-18-046-FR (2020 update)	Electric	Vertically Integrated	10/1/2020	5.31	NA	37.92
Arkansas	Southwestern Electric Power Co	AEP	D-21-070-U	Electric	Vertically Integrated	7/23/2021	4.74	9.50	44.54
Arizona	Arizona Public Service Co.	PNW	D-E-01345A-19-0236	Electric	Vertically Integrated	10/31/2019	6.62	8.70	54.67
California	Liberty Utilities (CalPeco Ele	AQN	A-21-05-017	Electric	Vertically Integrated	5/28/2021	NA	10.00	52.50
California	Pacific Gas and Electric Co.	PCG	A-22-12-009	Electric	Limited-Issue Rider	12/15/2022	NA	NA	NA
California	Pacific Gas and Electric Co.	PCG	A-22-04-008	Electric	Vertically Integrated	4/20/2022	7.27	10.00	52.00
California	Pacific Gas and Electric Co.	PCG	A-21-08-015	Electric	Vertically Integrated	8/23/2021	7.81	10.25	52.00
California	San Diego Gas & Electric Co.	SRE	A-22-04-012	Electric	Vertically Integrated	4/20/2022	7.18	9.95	52.00
California	San Diego Gas & Electric Co.	SRE	A-21-08-014 (Elec)	Electric	Vertically Integrated	8/23/2021	7.55	10.20	52.00
California	Southern California Edison Co.	EIX	A-22-04-009	Electric	Vertically Integrated	4/20/2022	7.44	10.05	52.00
California	Southern California Edison Co.	EIX	A-21-08-013	Electric	Vertically Integrated	8/23/2021	7.68	10.30	52.00
California	Southern California Edison Co.	EIX	A-19-08-013 (Track 3)	Electric	Limited-Issue Rider	3/15/2021	NA	NA	NA
California	Southern California Edison Co.	EIX	A-19-08-013 (Track 2)	Electric	Limited-Issue Rider	9/25/2020	NA	NA	NA
California	Southern California Edison Co.	EIX	A-19-08-013 (Track 1)	Electric	Vertically Integrated	8/30/2019	7.68	NA	NA
Colorado	Public Service Co. of CO	XEL	D-21AL-0317E	Electric	Vertically Integrated	7/2/2021	6.82	9.30	55.69
District of Columbia	Potomac Electric Power Co.	EXC	FC-1156	Electric	Distribution	5/30/2019	7.17	9.28	50.68
Delaware	Delmarva Power & Light Co.	EXC	D-20-0149	Electric	Distribution	3/6/2020	6.80	9.60	NA
Florida	Duke Energy Florida LLC	DUK	D-20220143-EI	Electric	Limited-Issue Rider	8/12/2022	NA	10.10	NA
Florida	Duke Energy Florida LLC	DUK	D-20210016-EI	Electric	Vertically Integrated	1/14/2021	6.14	9.85	44.84
Florida	Florida Power & Light Co.	NEE	20210015 - ROE trigger	Electric	Limited-Issue Rider	8/23/2022	NA	10.80	NA
Florida	Florida Power & Light Co.	NEE	D-20210015-EI	Electric	Vertically Integrated	1/11/2021	NA	10.60	NA
Florida	Tampa Electric Company	EMA	D-20220148	Electric	Limited-Issue Rider	8/26/2022	6.38	10.20	45.07
Florida	Tampa Electric Company	EMA	D-20220122-EI	Electric	Limited-Issue Rider	7/1/2022	NA	10.20	NA
Florida	Tampa Electric Company	EMA	D-20210034-EI	Electric	Vertically Integrated	2/1/2021	6.26	9.95	45.07

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Rate Case History (Past Rate Cases)

List: None
Company List: All
States: All
Years: 2023, 2022, 2021
Service Type: All

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Increase Authorized			
						Date	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)
Georgia	Georgia Power Co.	SO	D-44280	Electric	Vertically Integrated	6/24/2022	7.43	10.50	56.00
Georgia	Georgia Power Co.	SO	D-43838	Electric	Limited-Issue Rider	6/15/2021	NA	NA	NA
Idaho	Avista Corp.	AVA	C-AVU-E-21-01	Electric	Vertically Integrated	1/29/2021	7.05	9.40	50.00
Idaho	Idaho Power Co.	IDA	C-IPC-E-21-17	Electric	Limited-Issue Rider	6/3/2021	NA	NA	NA
Idaho	PacifiCorp	BRK.A	C-PAC-E-21-07	Electric	Vertically Integrated	5/27/2021	NA	NA	NA
Illinois	Ameren Illinois	AEE	D-22-0297	Electric	Distribution	4/14/2022	5.90	7.85	50.00
Illinois	Ameren Illinois	AEE	D-21-0365	Electric	Distribution	4/15/2021	5.78	7.36	51.00
Illinois	Commonwealth Edison Co.	EXC	D-22-0302	Electric	Distribution	4/15/2022	5.94	7.85	49.45
Illinois	Commonwealth Edison Co.	EXC	D-21-0367	Electric	Distribution	4/16/2021	5.72	7.36	48.70
Indiana	AES Indiana	AES	Ca-45264-TDSIC-5	Electric	Limited-Issue Rider	6/23/2022	NA	NA	NA
Indiana	AES Indiana	AES	Ca-45264-TDSIC-3	Electric	Limited-Issue Rider	6/23/2021	NA	NA	NA
Indiana	Duke Energy Indiana, LLC	DUK	Ca-44720-TDSIC-11	Electric	Limited-Issue Rider	4/28/2022	NA	NA	NA
Indiana	Duke Energy Indiana, LLC	DUK	Ca-44720-TDSIC-9	Electric	Limited-Issue Rider	4/28/2021	NA	NA	NA
Indiana	Indiana Michigan Power Co.	AEP	Ca-45576	Electric	Vertically Integrated	7/1/2021	5.78	9.70	40.70
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45557-TDSIC-2	Electric	Limited-Issue Rider	9/27/2022	NA	NA	NA
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45557-TDSIC-1	Electric	Limited-Issue Rider	3/30/2022	NA	NA	NA
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-44733-TDSIC-9	Electric	Limited-Issue Rider	9/28/2021	NA	NA	NA
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-44733-TDSIC-8	Electric	Limited-Issue Rider	3/29/2021	NA	NA	NA
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-44733-TDSIC-7	Electric	Limited-Issue Rider	9/29/2020	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44910-TDSIC-12	Electric	Limited-Issue Rider	2/1/2023	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44910-TDSIC-11	Electric	Limited-Issue Rider	8/1/2022	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44910-TDSIC-10	Electric	Limited-Issue Rider	2/1/2022	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44910-TDSIC-9	Electric	Limited-Issue Rider	8/2/2021	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44910-TDSIC-8	Electric	Limited-Issue Rider	2/1/2021	NA	NA	NA
Kansas	The Empire District Electric C	AQN	D-21-EPDE-444-RTS	Electric	Vertically Integrated	5/28/2021	NA	NA	NA
Kentucky	Kentucky Power Co.	AEP	C-2020-00174	Electric	Vertically Integrated	6/29/2020	6.19	9.30	43.25
Kentucky	Kentucky Utilities Co.	PPL	C-2020-00349	Electric	Vertically Integrated	11/25/2020	NA	9.43	NA
Kentucky	Louisville Gas & Electric Co.	PPL	C-2020-00350 (elec.)	Electric	Vertically Integrated	11/25/2020	NA	9.43	NA

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Rate Case History (Past Rate Cases)

List: None
Company List: All
States: All
Years: 2023, 2022, 2021
Service Type: All

State	Company	Parent Company Ticker	Docket	Rate Case Service Type	Case Type	Increase Authorized			
						Increase Date	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)
Louisiana	Cleco Power LLC		D-U-35299	Electric	Vertically Integrated	6/28/2019	NA	NA	NA
Louisiana	Southwestern Electric Power Co	AEP	D-U-35441	Electric	Vertically Integrated	12/13/2019	NA	9.50	NA
Massachusetts	Massachusetts Electric Co.	NG.	DPU 22-73	Electric	Distribution	6/17/2022	NA	NA	NA
Massachusetts	Massachusetts Electric Co.	NG.	DPU 21-74	Electric	Distribution	6/15/2021	NA	NA	NA
Massachusetts	NSTAR Electric Co.	ES	DPU 22-22	Electric	Distribution	1/14/2022	7.06	9.80	53.21
Massachusetts	NSTAR Electric Co.	ES	DPU 21-106	Electric	Distribution	9/15/2021	NA	NA	NA
Maryland	Delmarva Power & Light Co.	EXC	C-9681	Electric	Distribution	5/19/2022	6.62	9.60	50.50
Maryland	Delmarva Power & Light Co.	EXC	C-9670	Electric	Distribution	9/1/2021	NA	NA	NA
Maryland	Potomac Electric Power Co.	EXC	C-9655	Electric	Distribution	10/26/2020	7.21	9.55	50.50
Maine	Central Maine Power Co.	IBE	D-2022-00152	Electric	Distribution	8/11/2022	NA	9.35	50.00
Maine	Versant Power		D-2022-00255	Electric	Distribution	10/3/2022	6.59	9.35	49.00
Maine	Versant Power		D-2020-00316	Electric	Distribution	1/19/2021	6.57	9.35	49.00
Michigan	Consumers Energy Co.	CMS	C-U-21224	Electric	Vertically Integrated	4/25/2022	NA	9.90	NA
Michigan	Consumers Energy Co.	CMS	C-U-20963	Electric	Vertically Integrated	3/1/2021	5.62	9.90	41.84
Michigan	DTE Electric Co.	DTE	C-U-20836	Electric	Vertically Integrated	1/18/2022	5.42	9.90	39.62
Michigan	Upper Peninsula Power Co.		C-U-21286	Electric	Vertically Integrated	9/8/2022	NA	9.90	NA
Minnesota	Minnesota Power Entrprs Inc.	ALE	D-E-015/GR-21-335	Electric	Vertically Integrated	11/1/2021	7.12	9.65	52.50
Minnesota	Northern States Power Co.	XEL	D-E-002/GR-21-630	Electric	Vertically Integrated	10/25/2021	NA	9.25	52.50
Minnesota	Northern States Power Co.	XEL	D-E-002/GR-20-723	Electric	Vertically Integrated	11/2/2020	NA	NA	NA
Minnesota	Otter Tail Power Co.	OTTR	D-E-017/GR-20-719	Electric	Vertically Integrated	11/2/2020	7.18	9.48	52.50
Missouri	Evergy Metro Inc	EVRG	C-ER-2022-0129	Electric	Vertically Integrated	1/7/2022	NA	NA	NA
Missouri	Evergy Missouri West	EVRG	C-ER-2022-0130	Electric	Vertically Integrated	1/7/2022	NA	NA	NA
Missouri	The Empire District Electric C	AQN	C-ER-2021-0312	Electric	Vertically Integrated	5/28/2021	NA	NA	NA
Missouri	Union Electric Co.	AEE	C-ER-2022-0337	Electric	Vertically Integrated	8/1/2022	NA	NA	NA
Missouri	Union Electric Co.	AEE	C-ER-2021-0240	Electric	Vertically Integrated	3/31/2021	NA	NA	NA
North Carolina	Duke Energy Carolinas LLC	DUK	D-E-7, Sub 1214	Electric	Vertically Integrated	9/30/2019	7.04	9.60	52.00
North Carolina	Duke Energy Carolinas LLC	DUK	D-E-7, Sub 1146	Electric	Vertically Integrated	8/25/2017	7.35	9.90	52.00
North Carolina	Duke Energy Progress LLC	DUK	D-E-2, Sub 1219	Electric	Vertically Integrated	10/30/2019	6.92	9.60	52.00
North Dakota	MDU Resources Group	MDU	C-PU-22-194	Electric	Vertically Integrated	5/16/2022	7.13	9.75	50.81

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List: None
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States: All
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						Date	Return on Original Cost Rate (%)	Return on Equity (%)	Common Equity to Total Capital (%)
North Dakota	Northern States Power Co.	XEL	C-PU-20-441	Electric	Vertically Integrated	11/6/2020	6.97	9.50	52.50
New Hampshire	Unitil Energy Systems Inc.	UTL	D-DE-21-030	Electric	Distribution	4/2/2021	7.42	9.20	52.00
New Jersey	Atlantic City Electric Co.	EXC	D-ER20120746	Electric	Distribution	12/9/2020	6.99	9.60	50.21
New Jersey	Rockland Electric Company	ED	D-ER21050823	Electric	Distribution	5/21/2021	7.08	9.60	48.51
New Mexico	El Paso Electric Co.		C-20-00104-UT	Electric	Vertically Integrated	5/29/2020	7.18	9.00	49.21
New Mexico	Southwestern Public Svc Co.	XEL	C-20-00238-UT	Electric	Vertically Integrated	1/4/2021	7.07	9.35	54.72
Nevada	Sierra Pacific Power Co.	BRK.A	D-22-06014	Electric	Vertically Integrated	6/6/2022	6.98	9.56	52.40
New York	Central Hudson Gas & Electric	FTS	C-20-E-0428	Electric	Distribution	8/27/2020	6.48	9.00	50.00
New York	Niagara Mohawk Power Corp.	NG.	C-20-E-0380	Electric	Distribution	7/31/2020	6.08	9.00	48.00
New York	Orange & Rockland Utlts Inc.	ED	C-21-E-0074	Electric	Distribution	1/29/2021	6.77	9.20	48.00
Ohio	Duke Energy Ohio Inc.	DUK	C-21-0887-EL-AIR	Electric	Distribution	10/1/2021	6.86	9.50	50.50
Ohio	Ohio Power Co.	AEP	C-20-0585-EL-AIR	Electric	Distribution	6/1/2020	7.28	9.70	54.43
Ohio	The Dayton Power & Light Co.	AES	C-20-1651-EL-AIR	Electric	Distribution	11/30/2020	7.43	10.00	53.87
Oklahoma	Oklahoma Gas and Electric Co.	OGE	Ca-PUD202100164	Electric	Vertically Integrated	12/30/2021	NA	9.50	53.37
Oklahoma	Public Service Co. of OK	AEP	Ca-PUD202100055	Electric	Vertically Integrated	4/30/2021	6.74	9.40	NA
Oklahoma	The Empire District Electric C	AQN	Ca-PUD202100163	Electric	Vertically Integrated	2/28/2022	NA	9.30	NA
Oregon	PacifiCorp	BRK.A	D-UE-399	Electric	Vertically Integrated	3/1/2022	7.11	9.50	50.00
Oregon	Portland General Electric Co.	POR	D-UE-394	Electric	Vertically Integrated	7/9/2021	6.81	9.50	50.00
Pennsylvania	Duquesne Light Co.		D-R-2021-3024750	Electric	Distribution	4/16/2021	NA	NA	NA
Pennsylvania	PECO Energy Co	EXC	D-R-2021-3024601	Electric	Distribution	3/31/2021	NA	NA	NA
Pennsylvania	UGI Utilities Inc.	UGI	D-R-2021-3023618	Electric	Distribution	2/8/2021	NA	NA	NA
South Carolina	Dominion Energy South Carolina	D	D-2020-125-E	Electric	Vertically Integrated	8/14/2020	7.59	9.50	51.62
South Carolina	Duke Energy Progress LLC	DUK	D-2022-254-E	Electric	Vertically Integrated	9/1/2022	6.83	9.60	52.43
South Dakota	Northern States Power Co.	XEL	D-EL22-017	Electric	Vertically Integrated	6/30/2022	6.82	NA	NA
Tennessee	Kingsport Power Company	AEP	D-21-00107	Electric	Vertically Integrated	11/17/2021	6.02	9.50	48.90
Texas	Cross Texas Transmission		D-51534	Electric	Transmission	11/19/2020	NA	NA	NA
Texas	El Paso Electric Co.		D-52195	Electric	Vertically Integrated	6/1/2021	7.50	9.35	51.00
Texas	Electric Transmission Texas		D-54608	Electric	Transmission	2/1/2023	NA	NA	NA

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Texas	Electric Transmission Texas		D-54502	Electric	Transmission	12/20/2022	NA	NA	NA
Texas	Electric Transmission Texas		D-51583	Electric	Transmission	12/4/2020	NA	NA	NA
Texas	Oncor Electric Delivery Co.	SRE	D-53601	Electric	Distribution	5/13/2022	6.65	9.70	42.50
Texas	Sharyland Utilities L.L.C.	SRE	D-51611	Electric	Transmission	12/18/2020	5.75	9.38	40.00
Texas	Southwestern Electric Power Co	AEP	D-51415	Electric	Vertically Integrated	10/13/2020	6.69	9.25	49.37
Texas	Southwestern Public Svc Co.	XEL	D-51802	Electric	Vertically Integrated	2/8/2021	NA	NA	NA
Texas	Wind Energy Transmission Texas		D-54348	Electric	Transmission	11/15/2022	NA	NA	NA
Virginia	Appalachian Power Co.	AEP	C-PUR-2022-00020 (BC-RAC)	Electric	Limited-Issue Rider	6/8/2022	6.84	NA	49.78
Virginia	Appalachian Power Co.	AEP	C-PUR-2022-00001 (E-RAC)	Electric	Limited-Issue Rider	3/18/2022	6.81	NA	48.29
Virginia	Appalachian Power Co.	AEP	C-PUR-2021-00206 (RPS-RAC)	Electric	Limited-Issue Rider	12/30/2021	9.82	9.20	48.29
Virginia	Appalachian Power Co.	AEP	C-PUR-2021-00236 (RAC-EE)	Electric	Limited-Issue Rider	11/30/2021	NA	NA	NA
Virginia	Appalachian Power Co.	AEP	C-PUR-2021-00047 (GRAC)	Electric	Limited-Issue Rider	6/1/2021	6.82	9.20	48.29
Virginia	Appalachian Power Co.	AEP	C-PUR-2020-00259 (BC-RAC)	Electric	Limited-Issue Rider	1/28/2021	7.07	9.20	50.32
Virginia	Appalachian Power Co.	AEP	C-PUR-2020-00258 (E-RAC)	Electric	Limited-Issue Rider	12/23/2020	7.07	NA	50.32
Virginia	Appalachian Power Co.	AEP	C-PUR-2020-00251 (RAC-EE)	Electric	Limited-Issue Rider	11/30/2020	NA	9.20	NA
Virginia	Kentucky Utilities Co.	PPL	C-PUR-2021-00171	Electric	Vertically Integrated	8/31/2021	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00113(Roll in)	Electric	Limited-Issue Rider	5/1/2023	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00114 (Roll in)	Electric	Limited-Issue Rider	5/1/2023	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00090 (Roll in)	Electric	Limited-Issue Rider	5/1/2023	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00124 (Rider CE)	Electric	Limited-Issue Rider	10/14/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00162 (Rider SNA)	Electric	Limited-Issue Rider	10/6/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00164 (Rder US-2)	Electric	Limited-Issue Rider	10/5/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00140 (Rider GT)	Electric	Limited-Issue Rider	8/16/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00120 (Rider US3)	Electric	Limited-Issue Rider	8/2/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00121 (Rider US4)	Electric	Limited-Issue Rider	8/2/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00088 (Rider B)	Electric	Limited-Issue Rider	6/13/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00089 (Rider U)	Electric	Limited-Issue Rider	6/13/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00090 (Rider W)	Electric	Limited-Issue Rider	6/13/2022	7.36	10.35	52.29

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Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00070 (Rider RGGI)	Electric	Limited-Issue Rider	5/5/2022	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C- PUR-2022-00062(Rider RBB)	Electric	Limited-Issue Rider	5/5/2022	6.83	9.35	52.29
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00033 (Rider CCR)	Electric	Limited-Issue Rider	2/28/2022	6.90	9.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2022-00006 (Rider E)	Electric	Limited-Issue Rider	1/26/2022	6.90	9.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00247 (Rider DSM)	Electric	Limited-Issue Rider	12/14/2021	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00281 (Rider RGGI)	Electric	Limited-Issue Rider	12/6/2021	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00142 (Rider OSW)	Electric	Limited-Issue Rider	11/5/2021	6.81	9.20	51.82
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00229 (Rider SNA)	Electric	Limited-Issue Rider	10/5/2021	6.09	9.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00238 (Rider US-2)	Electric	Limited-Issue Rider	10/5/2021	6.90	9.20	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00239 (Rider BW)	Electric	Limited-Issue Rider	10/5/2021	7.42	10.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00146 (Rider CE)	Electric	Limited-Issue Rider	9/15/2021	6.81	9.20	51.82
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00083 (Rider GT)	Electric	Limited-Issue Rider	8/13/2021	6.90	9.20	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00118 (Rider US-3)	Electric	Limited-Issue Rider	8/2/2021	6.81	9.20	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00119 (Rider US-4)	Electric	Limited-Issue Rider	8/2/2021	6.81	9.20	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00111 (Rider B)	Electric	Limited-Issue Rider	6/8/2021	6.81	9.20	51.82
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00112 (Rider GV)	Electric	Limited-Issue Rider	6/8/2021	6.81	9.20	51.82
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00113 (Rider R)	Electric	Limited-Issue Rider	6/8/2021	6.90	9.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00114 (Rider S)	Electric	Limited-Issue Rider	6/8/2021	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00115 (Rider W)	Electric	Limited-Issue Rider	6/8/2021	7.33	10.20	51.82
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00110 (Rider U)	Electric	Limited-Issue Rider	6/8/2021	6.90	9.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00058	Electric	Vertically Integrated	3/31/2021	6.92	9.35	51.92
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00045 (Rider CCR)	Electric	Limited-Issue Rider	2/26/2021	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2021-00013 (Rider E)	Electric	Limited-Issue Rider	1/19/2021	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00274 (Rider DSM)	Electric	Limited-Issue Rider	12/2/2020	NA	NA	NA
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00197 (Rider RBB)	Electric	Limited-Issue Rider	11/19/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00169 (Rider RGGI)	Electric	Limited-Issue Rider	11/9/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00134 (Rider CE)	Electric	Limited-Issue Rider	10/30/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00230 (Rider BW)	Electric	Limited-Issue Rider	10/5/2020	7.40	10.20	52.07

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Virginia	Virginia Electric & Power Co.	D	PUR-2020-00231 (Rider US-2)	Electric	Limited-Issue Rider	10/5/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00122 (Rider US-3)	Electric	Limited-Issue Rider	7/1/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00123 (Rider US-4)	Electric	Limited-Issue Rider	7/1/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00096 (Rider U)	Electric	Limited-Issue Rider	6/1/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00099 (Rider B)	Electric	Limited-Issue Rider	6/1/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00100 (Rider GV)	Electric	Limited-Issue Rider	6/1/2020	6.88	9.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00101 (Rider R)	Electric	Limited-Issue Rider	6/1/2020	6.95	9.34	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00102 (Rider S)	Electric	Limited-Issue Rider	6/1/2020	7.40	10.20	52.07
Virginia	Virginia Electric & Power Co.	D	C-PUR-2020-00103 (Rider W)	Electric	Limited-Issue Rider	6/1/2020	7.40	10.20	52.07
Vermont	Green Mountain Power Corp.		C-22-0175-TF	Electric	Vertically Integrated	1/18/2022	6.30	8.57	49.98
Vermont	Green Mountain Power Corp.		21-1963-TF	Electric	Vertically Integrated	6/1/2021	6.67	8.57	50.42
Washington	Avista Corp.	AVA	D-UE-220053	Electric	Vertically Integrated	1/21/2022	7.03	NA	NA
Washington	Avista Corp.	AVA	D-UE-200900	Electric	Vertically Integrated	10/30/2020	7.12	9.40	48.50
Washington	Puget Sound Energy Inc.		D-UE-220066	Electric	Vertically Integrated	1/31/2022	7.16	9.40	49.00
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-124 (Elec)	Electric	Vertically Integrated	5/3/2021	7.18	9.80	55.00
Wisconsin	Northern States Power Co.	XEL	D-4220-UR-125 (Elec)	Electric	Vertically Integrated	7/2/2021	7.31	10.00	52.50
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-UR-110 (WEP-Elec)	Electric	Vertically Integrated	4/28/2022	8.77	9.80	58.22
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-AF-107 (WEP-Elec)	Electric	Vertically Integrated	3/30/2021	NA	NA	NA
Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-123 (Elec)	Electric	Vertically Integrated	5/5/2021	7.48	10.00	52.50
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-127 (Elec)	Electric	Vertically Integrated	4/28/2022	7.52	9.80	53.40
Wisconsin	Wisconsin Public Service Corp.	WEC	D-5-AF-107 (Elec)	Electric	Vertically Integrated	3/30/2021	NA	NA	NA
West Virginia	Appalachian Power Co.	AEP	C-22-0393-E-ENEC	Electric	Limited-Issue Rider	4/19/2022	NA	NA	NA
West Virginia	Appalachian Power Co.	AEP	C-22-0304-E-P	Electric	Limited-Issue Rider	3/15/2022	NA	NA	NA
West Virginia	Appalachian Power Co.	AEP	C-21-0339-E-ENEC	Electric	Limited-Issue Rider	4/16/2021	NA	NA	NA
West Virginia	Appalachian Power Co.	AEP	C-20-1012-E-P	Electric	Limited-Issue Rider	12/14/2020	NA	9.25	NA
West Virginia	Monongahela Power Co.	FE	C-22-0793-E-ENEC	Electric	Limited-Issue Rider	8/25/2022	NA	NA	NA
West Virginia	Monongahela Power Co.	FE	C-21-0658-E-ENEC	Electric	Limited-Issue Rider	8/27/2021	NA	NA	NA
Wyoming	Cheyenne Light Fuel Power Co.	BKH	D-20003-214-ER-22	Electric	Vertically Integrated	6/1/2022	7.48	9.75	52.00

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Wyoming	PacifiCorp	BRK.A	D-20000-578-ER-20	Electric	Vertically Integrated	3/4/2020	7.19	9.50	51.00
Arizona	Southwest Gas Corp.	SWX	D-G-01551A-21-0368	Natural Gas	Distribution	12/3/2021	6.73	9.30	50.00
California	San Diego Gas & Electric Co.	SRE	A-21-08-014 (Gas)	Natural Gas	Distribution	8/23/2021	7.55	10.20	52.00
California	Southern California Gas Co.	SRE	A-22-04-011	Natural Gas	Distribution	4/20/2022	7.10	9.80	52.00
California	Southwest Gas Corp.	SWX	A-19-08-015 (SoCal)	Natural Gas	Distribution	8/30/2019	7.11	10.00	52.00
California	Southwest Gas Corp.	SWX	A-19-08-015 (NoCal)	Natural Gas	Distribution	8/30/2019	7.44	10.00	52.00
California	Southwest Gas Corp.	SWX	A-19-08-015 (LkTah)	Natural Gas	Distribution	8/30/2019	7.44	10.00	52.00
Colorado	Atmos Energy Corp.	ATO	D-22AL-0348G	Natural Gas	Distribution	8/5/2022	7.00	9.30	58.00
Colorado	Black Hills Colorado Gas Inc.	BKH	D-21AL-0236G	Natural Gas	Distribution	6/1/2021	6.56	9.20	50.26
Colorado	Black Hills Colorado Gas Inc.	BKH	D-20AL-0380G	Natural Gas	Distribution	9/11/2020	NA	NA	NA
Colorado	Public Service Co. of CO	XEL	D-22AL-0046G	Natural Gas	Distribution	1/24/2022	6.70	9.20	53.78
District of Columbia	Washington Gas Light Co.	ALA	FC-1162	Natural Gas	Distribution	1/13/2020	7.05	9.25	52.10
Delaware	Delmarva Power & Light Co.	EXC	D-22-0002	Natural Gas	Distribution	1/14/2022	6.57	9.60	49.94
Delaware	Delmarva Power & Light Co.	EXC	D-20-0150	Natural Gas	Distribution	2/21/2020	6.80	9.60	50.37
Florida	Florida Public Utilities Co.	CPK	D-20220067-GU	Natural Gas	Distribution	5/24/2022	5.97	10.25	45.16
Florida	Pivotal Utility Holdings Inc.	NEE	20220069-GU	Natural Gas	Distribution	5/31/2022	6.44	9.50	59.60
Georgia	Atlanta Gas Light Co.	SO	D-42315 (2021 review)	Natural Gas	Distribution	7/21/2021	NA	NA	56.00
Georgia	Atlanta Gas Light Co.	SO	D-42315 (2020 review)	Natural Gas	Distribution	7/1/2020	7.72	NA	56.00
Iowa	Black Hills Iowa Gas Utility	BKH	D-RPU-2021-0002	Natural Gas	Distribution	6/1/2021	6.75	9.60	50.01
Idaho	Avista Corp.	AVA	C-AVU-G-21-01	Natural Gas	Distribution	1/29/2021	7.05	9.40	50.00
Illinois	Ameren Illinois	AEE	D-20-0308	Natural Gas	Distribution	2/21/2020	7.14	9.67	52.00
Illinois	North Shore Gas Co.	WEC	D-20-0810	Natural Gas	Distribution	10/15/2020	6.63	9.67	51.58
Illinois	Northern Illinois Gas Co.	SO	D-21-0098	Natural Gas	Distribution	1/14/2021	6.96	9.75	54.46
Indiana	Indiana Gas Co.	CNP	Ca-45611-TDSIC-1	Natural Gas	Limited-Issue Rider	10/3/2022	NA	NA	NA
Indiana	Indiana Gas Co.	CNP	Ca-44430-TDSIC-14	Natural Gas	Limited-Issue Rider	4/1/2021	NA	NA	NA
Indiana	Indiana Gas Co.	CNP	Ca-45468	Natural Gas	Distribution	12/18/2020	6.16	9.80	46.21
Indiana	Indiana Gas Co.	CNP	Ca-44430-TDSIC-13	Natural Gas	Limited-Issue Rider	10/1/2020	NA	NA	NA
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45330-TDSIC-4	Natural Gas	Limited-Issue Rider	3/1/2022	NA	NA	NA

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Years: 2023, 2022, 2021
Service Type: All

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Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45621	Natural Gas	Distribution	9/29/2021	6.55	9.85	49.47
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45330-TDSIC-3	Natural Gas	Limited-Issue Rider	8/24/2021	NA	NA	NA
Indiana	Northern IN Public Svc Co. LLC	NI	Ca-45330-TDSIC-2	Natural Gas	Limited-Issue Rider	2/23/2021	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-45612-TDSIC-1	Natural Gas	Limited-Issue Rider	10/3/2022	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44429-TDSIC-14	Natural Gas	Limited-Issue Rider	4/1/2021	NA	NA	NA
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-45447	Natural Gas	Distribution	10/30/2020	5.78	9.70	45.74
Indiana	Sthrn IN Gas & Electric Co.	CNP	Ca-44429-TDSIC-13	Natural Gas	Limited-Issue Rider	10/1/2020	NA	NA	NA
Kansas	Atmos Energy Corp.	ATO	D-23-ATMG-581-TAR (SIP)	Natural Gas	Limited-Issue Rider	1/19/2023	NA	NA	NA
Kansas	Atmos Energy Corp.	ATO	D-23-ATMG-359-RTS	Natural Gas	Distribution	9/9/2022	NA	NA	NA
Kansas	Atmos Energy Corp.	ATO	D-22-ATMG-299-TAR (SIP)	Natural Gas	Limited-Issue Rider	1/14/2022	NA	NA	NA
Kansas	Atmos Energy Corp.	ATO	D-22-ATMG-203-TAR (GSRS)	Natural Gas	Limited-Issue Rider	11/4/2021	NA	NA	NA
Kansas	Atmos Energy Corp.	ATO	D-21-ATMG-180-TAR (GSRS)	Natural Gas	Limited-Issue Rider	11/3/2020	NA	NA	NA
Kansas	Black Hills Kansas Gas Utility	BKH	D-22-BHCG-503-TAR (GSRS)	Natural Gas	Limited-Issue Rider	5/9/2022	NA	NA	NA
Kansas	Black Hills Kansas Gas Utility	BKH	D-21-BHCG-434-TAR (GSRS)	Natural Gas	Limited-Issue Rider	5/21/2021	NA	NA	NA
Kansas	Black Hills Kansas Gas Utility	BKH	D-21-BHCG-418-RTS	Natural Gas	Distribution	5/7/2021	NA	NA	NA
Kansas	Kansas Gas Service Co.	OGS	D-23-KGSG-281-TAR (GSRS)	Natural Gas	Limited-Issue Rider	8/26/2022	NA	NA	NA
Kansas	Kansas Gas Service Co.	OGS	D-22-KGSG-112-TAR (GSRS)	Natural Gas	Limited-Issue Rider	8/26/2021	NA	NA	NA
Kentucky	Atmos Energy Corp.	ATO	C-2022-00222 (PRP)	Natural Gas	Limited-Issue Rider	7/29/2022	6.94	9.55	54.50
Kentucky	Atmos Energy Corp.	ATO	C-2021-00304 (PRP)	Natural Gas	Limited-Issue Rider	7/30/2021	NA	NA	NA
Kentucky	Atmos Energy Corp.	ATO	C-2021-00214	Natural Gas	Distribution	6/30/2021	6.82	9.23	54.50
Kentucky	Columbia Gas of Kentucky Inc	NI	C-2021-00183	Natural Gas	Distribution	5/28/2021	6.89	9.35	52.64
Kentucky	Delta Natural Gas Co.	WTRG	C-2021-00185	Natural Gas	Distribution	5/28/2021	NA	9.25	NA
Kentucky	Delta Natural Gas Co.	WTRG	C-2021-00098 (PRP)	Natural Gas	Limited-Issue Rider	2/26/2021	NA	NA	NA
Kentucky	Duke Energy Kentucky Inc.	DUK	C-2021-00190	Natural Gas	Distribution	6/1/2021	6.54	9.38	51.34
Kentucky	Louisville Gas & Electric Co.	PPL	C-2020-00350 (gas)	Natural Gas	Distribution	11/25/2020	NA	9.43	NA
Massachusetts	Boston Gas Co.	NG.	DPU 22-74	Natural Gas	Distribution	6/17/2022	NA	NA	NA
Massachusetts	Boston Gas Co.	NG.	DPU 20-120	Natural Gas	Distribution	11/13/2020	6.98	9.70	53.44
Massachusetts	NSTAR Gas Co.	ES	DPU 21-107	Natural Gas	Distribution	9/15/2021	NA	NA	NA
Massachusetts	The Berkshire Gas Co.	IBE	DPU 22-20	Natural Gas	Distribution	6/24/2022	7.20	9.70	54.00

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Maryland	Columbia Gas of Maryland Inc	NI	C-9680	Natural Gas	Distribution	5/13/2022	7.11	9.65	52.97
Maryland	Columbia Gas of Maryland Inc	NI	C-9664	Natural Gas	Distribution	5/14/2021	7.06	9.65	52.95
Maryland	Washington Gas Light Co.	ALA	C-9651	Natural Gas	Distribution	8/28/2020	7.09	9.70	52.03
Michigan	Consumers Energy Co.	CMS	C-U-21148	Natural Gas	Distribution	12/1/2021	NA	9.90	NA
Michigan	DTE Gas Co.	DTE	C-U-20940	Natural Gas	Distribution	2/12/2021	5.41	9.90	39.23
Michigan	Michigan Gas Utilities Corp.	WEC	C-U-20718	Natural Gas	Distribution	3/22/2021	NA	9.85	NA
Minnesota	CenterPoint Energy Resources	CNP	D-G-008/GR-21-435	Natural Gas	Distribution	11/1/2021	6.65	9.39	51.00
Minnesota	CenterPoint Energy Resources	CNP	D-G-008/GR-19-524	Natural Gas	Distribution	10/28/2019	6.86	NA	NA
Minnesota	Northern States Power Co.	XEL	D-G-002/GR-21-678	Natural Gas	Distribution	11/1/2021	6.97	9.57	52.50
Missouri	Empire District Gas Co.	AQN	C-GR-2021-0320	Natural Gas	Distribution	8/16/2021	NA	NA	NA
Missouri	Liberty Utilities (Midstates)	AQN	C-GT-2021-0073 (ISRS)	Natural Gas	Limited-Issue Rider	12/31/2020	NA	NA	NA
Missouri	Spire Missouri Inc.	SR	C-GO-2023-0203 (ISRS)	Natural Gas	Limited-Issue Rider	12/27/2022	NA	NA	NA
Missouri	Spire Missouri Inc.	SR	C-GO-2022-0339 (ISRS)	Natural Gas	Limited-Issue Rider	6/3/2022	NA	NA	NA
Missouri	Spire Missouri Inc.	SR	C-GR-2022-0179	Natural Gas	Distribution	4/1/2022	NA	NA	NA
Missouri	Spire Missouri Inc.	SR	C-GO-2022-0171 (ISRS)	Natural Gas	Limited-Issue Rider	12/23/2021	NA	NA	NA
Missouri	Spire Missouri Inc.	SR	C-GR-2021-0108	Natural Gas	Distribution	12/11/2020	6.37	9.37	49.86
Missouri	Union Electric Co.	AEE	C-GR-2021-0241	Natural Gas	Distribution	3/31/2021	NA	NA	NA
Montana	MDU Resources Group	MDU	D2020.06.076	Natural Gas	Distribution	6/22/2020	NA	NA	NA
North Carolina	Piedmont Natural Gas Co.	DUK	D-G-9, Sub 781	Natural Gas	Distribution	3/22/2021	6.90	9.60	51.60
North Carolina	Public Service Co. of NC	D	D-G-5 Sub 632	Natural Gas	Distribution	4/1/2021	7.07	9.60	51.60
North Dakota	MDU Resources Group	MDU	C-PU-20-379	Natural Gas	Distribution	8/26/2020	6.85	9.30	50.31
North Dakota	Northern States Power Co.	XEL	C-PU-21-381	Natural Gas	Distribution	9/2/2021	NA	9.80	52.54
Nebraska	Black Hills Nebraska Gas LLC	BKH	D-NG-109	Natural Gas	Distribution	6/1/2020	6.71	9.50	50.00
New Hampshire	Liberty Utilities EnergyNorth	AQN	D-DG-20-105	Natural Gas	Distribution	7/31/2020	6.96	9.30	52.00
New Hampshire	Northern Utilities Inc.	UTL	D-DG-21-104	Natural Gas	Distribution	8/2/2021	7.20	9.30	52.00
New Jersey	Elizabethtown Gas Co.	JPM	D-GR21121254	Natural Gas	Distribution	12/28/2021	6.83	9.60	52.00
New Jersey	New Jersey Natural Gas Co.	NJR	D-GR21030679	Natural Gas	Distribution	3/30/2021	6.84	9.60	54.00
New Jersey	South Jersey Gas Co.	JPM	D-GR22040253	Natural Gas	Distribution	4/15/2022	6.93	9.60	54.00

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New Mexico	New Mexico Gas Co.	EMA	C-21-00267-UT	Natural Gas	Distribution	12/13/2021	6.44	9.38	52.00
Nevada	Southwest Gas Corp.	SWX	D-21-09001 (Southern)	Natural Gas	Distribution	9/1/2021	NA	9.40	50.00
Nevada	Southwest Gas Corp.	SWX	D-21-09001 (Northern)	Natural Gas	Distribution	9/1/2021	NA	9.40	50.00
New York	Central Hudson Gas & Electric	FTS	C-20-G-0429	Natural Gas	Distribution	8/27/2020	6.48	9.00	50.00
New York	Corning Natural Gas Corp.		C-21-G-0394	Natural Gas	Distribution	7/16/2021	6.53	9.25	48.00
New York	Corning Natural Gas Corp.		C-20-G-0101	Natural Gas	Distribution	2/27/2020	6.28	8.80	48.00
New York	KeySpan Gas East Corp.	NG.	C-19-G-0310	Natural Gas	Distribution	4/30/2019	6.32	8.80	48.00
New York	Niagara Mohawk Power Corp.	NG.	C-20-G-0381	Natural Gas	Distribution	7/31/2020	6.08	9.00	48.00
New York	Orange & Rockland Utlts Inc.	ED	C-21-G-0073	Natural Gas	Distribution	1/29/2021	6.77	9.20	48.00
New York	The Brooklyn Union Gas Co.	NG.	C-19-G-0309	Natural Gas	Distribution	4/30/2019	6.34	8.80	48.00
Ohio	Columbia Gas Ohio Inc.	NI	C-21-0637-GA-AIR	Natural Gas	Distribution	6/30/2021	7.08	9.60	50.60
Oklahoma	CenterPoint Energy Resources	CNP	Ca-PUD202100054	Natural Gas	Distribution	3/15/2021	NA	NA	NA
Oklahoma	Oklahoma Natural Gas Co	OGS	Ca-PUD202200023	Natural Gas	Distribution	3/15/2022	NA	NA	NA
Oklahoma	Oklahoma Natural Gas Co	OGS	Ca-PUD202100063	Natural Gas	Distribution	5/28/2021	7.20	9.40	58.55
Oklahoma	Summit Utilities Inc.	JPM	Ca-PUD202200022	Natural Gas	Distribution	3/15/2022	NA	NA	NA
Oregon	Avista Corp.	AVA	D-UG 433	Natural Gas	Distribution	10/22/2021	7.05	9.40	50.00
Oregon	Cascade Natural Gas Corp.	MDU	D-UG 390	Natural Gas	Distribution	3/31/2020	7.07	9.40	50.00
Oregon	Northwest Natural Gas Co.	NWN	D-UG-435	Natural Gas	Distribution	12/17/2021	6.84	9.40	50.00
Pennsylvania	Columbia Gas of Pennsylvania	NI	D-R-2022-3031211	Natural Gas	Distribution	3/18/2022	NA	NA	NA
Pennsylvania	Columbia Gas of Pennsylvania	NI	D-R-2021-3024296	Natural Gas	Distribution	3/30/2021	NA	NA	NA
Pennsylvania	Columbia Gas of Pennsylvania	NI	D-R-2020-3018835	Natural Gas	Distribution	4/24/2020	7.41	9.86	54.19
Pennsylvania	Natl Fuel Gas Distribution Cor	NFG	D-R-2022-3035730	Natural Gas	Distribution	10/28/2022	NA	NA	NA
Pennsylvania	PECO Energy Co	EXC	D-R-2022-3031113	Natural Gas	Distribution	3/31/2022	NA	NA	NA
Pennsylvania	PECO Energy Co	EXC	D-R-2020-3018929	Natural Gas	Distribution	9/30/2020	7.26	10.24	53.38
Pennsylvania	UGI Utilities Inc.	UGI	D-R-2021-3030218	Natural Gas	Distribution	1/28/2022	NA	NA	NA
South Carolina	Piedmont Natural Gas Co.	DUK	D-2022-89-G	Natural Gas	Distribution	4/1/2022	6.80	9.30	52.20
South Carolina	Piedmont Natural Gas Co.	DUK	D-2021-7-G	Natural Gas	Distribution	6/15/2021	7.07	9.80	52.20
South Dakota	MidAmerican Energy Co.	BRK.A	D-NG22-005	Natural Gas	Distribution	5/18/2022	6.75	NA	NA

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Tennessee	Atmos Energy Corp.	ATO	D-22-00010	Natural Gas	Distribution	2/1/2022	7.53	NA	60.59
Tennessee	Atmos Energy Corp.	ATO	D-21-00019	Natural Gas	Distribution	2/1/2021	7.62	NA	59.88
Tennessee	Piedmont Natural Gas Co.	DUK	D-20-00086	Natural Gas	Distribution	7/2/2020	6.85	9.80	50.50
Texas	Texas Gas Service Co.	OGS	D-OSS-22-00009896	Natural Gas	Distribution	6/30/2022	7.38	9.60	59.74
Utah	Dominion Energy Inc.	D	D-22-057-03	Natural Gas	Distribution	5/2/2022	6.86	9.60	51.00
Virginia	Columbia Gas of Virginia Inc	NI	C-PUR-2022-00126 (SAVE)	Natural Gas	Limited-Issue Rider	8/15/2022	NA	NA	NA
Virginia	Columbia Gas of Virginia Inc	NI	C-PUR-2022-00036	Natural Gas	Distribution	4/29/2022	NA	NA	NA
Virginia	Columbia Gas of Virginia Inc	NI	C-PUR-2021-00145(SAVE)	Natural Gas	Limited-Issue Rider	8/12/2021	NA	NA	NA
Virginia	Roanoke Gas Co.	RGCO	C-PUR-2022-00125 (Rider RNG)	Natural Gas	Limited-Issue Rider	8/3/2022	7.90	10.44	59.63
Virginia	Roanoke Gas Co.	RGCO	C-PUR-2022-00086 (SAVE)	Natural Gas	Limited-Issue Rider	5/26/2022	NA	NA	NA
Virginia	Roanoke Gas Co.	RGCO	C-PUR-2021-00120 (SAVE)	Natural Gas	Limited-Issue Rider	6/1/2021	7.03	NA	NA
Virginia	Virginia Natural Gas Inc.	SO	C-PUR-2022-00115 (SAVE)	Natural Gas	Limited-Issue Rider	8/1/2022	NA	NA	NA
Virginia	Virginia Natural Gas Inc.	SO	C-PUR-2021-00157(SAVE)	Natural Gas	Limited-Issue Rider	7/30/2021	NA	NA	NA
Virginia	Virginia Natural Gas Inc.	SO	C-PUR-2020-00095	Natural Gas	Distribution	6/1/2020	7.05	9.50	51.89
Virginia	Washington Gas Light Co.	ALA	C-PUR-2022-00161 (SAVE)	Natural Gas	Limited-Issue Rider	9/23/2022	NA	NA	NA
Virginia	Washington Gas Light Co.	ALA	C-PUR-2021-00261 (SAVE)	Natural Gas	Limited-Issue Rider	10/26/2021	NA	NA	NA
Washington	Avista Corp.	AVA	D-UG-220054	Natural Gas	Distribution	1/21/2022	7.03	NA	NA
Washington	Avista Corp.	AVA	D-UG-200901	Natural Gas	Distribution	10/30/2020	7.12	9.40	48.50
Washington	Cascade Natural Gas Corp.	MDU	D-UG-210755	Natural Gas	Distribution	9/30/2021	6.85	9.40	47.00
Washington	Cascade Natural Gas Corp.	MDU	D-UG-200568	Natural Gas	Distribution	6/19/2020	6.95	9.40	49.10
Washington	Northwest Natural Gas Co.	NWN	D-UG-200994	Natural Gas	Distribution	12/18/2020	6.81	NA	NA
Washington	Puget Sound Energy Inc.		D-UG-220067	Natural Gas	Distribution	1/31/2022	7.16	9.40	49.00
Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-124 (Gas)	Natural Gas	Distribution	5/3/2021	NA	9.80	55.00
Wisconsin	Northern States Power Co.	XEL	D- 4220-UR-125 (Gas)	Natural Gas	Distribution	7/2/2021	7.31	10.00	52.50
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-UR-110 (WEP-Gas)	Natural Gas	Distribution	4/28/2022	8.29	9.80	58.22
Wisconsin	Wisconsin Electric Power Co.	WEC	D-5-AF-107 (WEP-Gas)	Natural Gas	Distribution	3/30/2021	NA	NA	NA
Wisconsin	Wisconsin Gas LLC	WEC	D-5-UR-110	Natural Gas	Distribution	4/28/2022	8.03	9.80	52.70
Wisconsin	Wisconsin Gas LLC	WEC	D-5-AF-107	Natural Gas	Distribution	3/30/2021	NA	NA	NA

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Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-123 (Gas)	Natural Gas	Distribution	5/5/2021	7.44	10.00	52.50
Wisconsin	Wisconsin Public Service Corp.	WEC	D-6690-UR-127 (Gas)	Natural Gas	Distribution	4/28/2022	7.54	9.80	53.40
Wisconsin	Wisconsin Public Service Corp.	WEC	D-5-AF-107 (Gas)	Natural Gas	Distribution	3/30/2021	NA	NA	NA
West Virginia	Hope Gas Inc.		D-21-0416-G-390P	Natural Gas	Limited-Issue Rider	5/27/2021	NA	NA	NA
West Virginia	Hope Gas Inc.		C-20-0746-G-42T	Natural Gas	Distribution	9/30/2020	5.98	9.54	47.45
West Virginia	Mountaineer Gas Co.	UGI	C-22-0709-G-390P (IREP)	Natural Gas	Limited-Issue Rider	7/29/2022	6.85	NA	47.18
West Virginia	Mountaineer Gas Co.	UGI	C-21-0593-G-390P	Natural Gas	Limited-Issue Rider	7/30/2021	6.85	NA	52.90

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Duke Energy Carolinas, LLC
Proxy Group Authorized Equity Ratios - per Exhibit BSL-12
(sorted by approval date)

Line	Utility	Equity Ratio	Case Decision Date - per S&P
1	Kentucky Power	43.25%	1/13/2021
2	Northern States Power ND	52.50%	8/18/2021
3	IDACORP	50%	9/1/2021
4	Otter Tail	52.50%	11/4/2021
5	AEP Ohio	54.43%	11/17/2021
6	TX Southwestern AEP	49.37%	11/18/2021
7	VA Electric Power	51.92%	11/18/2021
8	Northern States Power WI	52.50%	11/18/2021
9	Wisconsin Electric and Light	52.50%	11/18/2021
10	Entergy Arkansas	47%	12/7/2021
11	Consumers Energy	50.75%	12/22/2021
12	Southwestern Public Service NM	54.72%	2/16/2022
13	Indiana Michigan IN	49.46%	2/23/2022
14	Public Service Colorado Xcel	55.69%	3/16/2022
15	Portland General	50%	4/25/2022
16	SWEPCO	47%	5/23/2022
17	Kingsport TN	48.90%	10/25/2022
18	DTE		11/18/2022
19	Georgia Power	56%	12/20/2022
20	Wisconsin Public Service	53.40%	12/22/2022
21	Wisconsin Electric WEC	58.22%	12/29/2022
22	Northern States Power MN	52.50%	6/1/2023
23	Average (per LaConte)	51.55%	
24	Average 21 and prior	50.61%	
25	Average 22-23	52.59%	
26	Prior 12 months	53.80%	
27	Duke Energy Carolinas	53.00%	
28	CUCA	51.55%	

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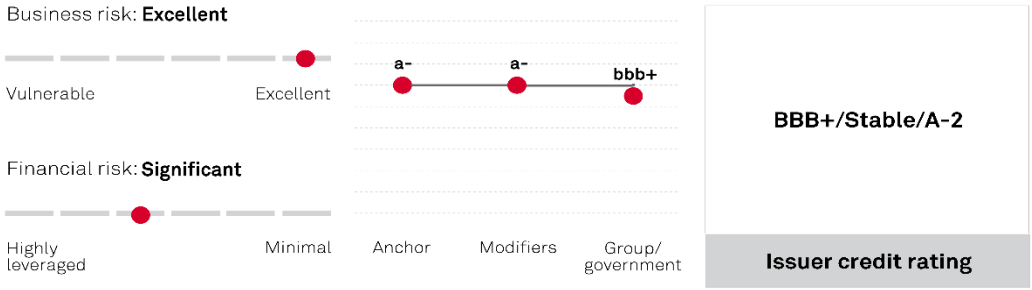
Ratings

Research

Duke Energy Carolinas LLC

May 8, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Duke Energy Carolinas LLC (DEC) is a lower-risk, vertically integrated utility with regulatory diversity in North and South Carolina.	DEC's service territory is exposed to hurricanes and severe storms, which is partially offset by storm securitization legislation that permits recovery for certain storm recovery costs.
DEC provides electric service to a large customer base of about 2.8 million, which supports cash flow stability.	The parent's clean energy transformation strategy could result in elevated capital spending for DEC for the next several years.
As DEC's parent Duke Energy executes a clean energy transformation strategy, we think such a move could reduce DEC's environmental risk exposure over the long term.	Negative discretionary cash flow over our forecast period indicates external funding needs.

The company is requesting a multiyear rate case plan in North Carolina, which we expect could help reduce regulatory lag. On Jan. 19, 2023, DEC filed a multiyear rate case application seeking a cumulative increase of about $823 million in electric base rates over three years, a requested

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10.4% return on equity, and a 53% capital structure (a change from the current 9.6% return on equity and 52% capital structure). Specifically, the company has requested an overall revenue increase of about $501 million in year one (including a $371.5 million traditional rate increase plus a performance-based regulation plan), about $172 million in year two, and about $150 million in year three. The rate increase includes transmission and distribution investments and investments in energy storage and solar assets.

Outlook

The stable rating outlook on DEC is tied to that of its parent, reflecting our expectation that Duke Energy Corp. and its subsidiaries will effectively manage regulatory risk despite its ongoing energy transition and high capital spending, which could weaken its management of regulatory risk and its financial measures. The stable outlook also reflects our expectation that Duke Energy will maintain a consistent consolidated funds from operations (FFO) to debt ratio of about 12%-14%.

Downside scenario

We could lower our ratings on DEC if we downgraded the parent, Duke Energy. We could downgrade Duke Energy over the next 12-24 months if Duke Energy's consolidated financial measures weakened, including FFO to debt of consistently below 12%. This could occur if the company experienced regulatory setbacks in its key regulatory jurisdictions or if the company increased its leverage because of its high capital spending plans. Alternatively, we could lower our ratings if its business risk increased because of weaker regulatory risk management or its strategic focus shifted away from predominantly lower-risk regulated utility operations.

Upside scenario

We could raise our ratings on DEC if we upgraded the parent, Duke Energy. We could upgrade Duke Energy over the next 12-24 months if the company maintained FFO to debt consistently exceeding 16%. This could occur if Duke Energy permanently reduced its leverage profile while demonstrating it can effectively manage its regulatory risk on a consistent basis and execute its current and longer-range growth plans in a manner that preserves its credit quality.

Our Base-Case Scenario

Assumptions

- Consistent use of regulatory cost recovery mechanisms.
- Sales volumes return to pre-pandemic levels.
- Capital spending averaging about $3.9 billion annually through 2025.
- Dividends to parent averaging about $675 million through 2025.
- Negative discretionary cash flow throughout the forecast period.

Key metrics

Duke Energy Carolinas LLC— Key Metrics*

	2021a	2022a	2023f	2024f

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FFO to debt (%)	20.7	21.2	19.0-21.0	19.0 – 21.0
Debt to EBITDA (x)	3.9	4.1	4.0-4.5	4.0-4.5
FFO interest coverage (x)	6.9	7.1	6.5-7.0	6.5-7.0

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast.

Company Description

DEC engages in the generation, transmission, distribution, and sale of electricity and serves about 2.8 million electric customers in North Carolina and South Carolina. DEC is a wholly owned subsidiary of Duke Energy.

Peer Comparison

Duke Energy Carolinas LLC--Peer Comparisons

	Duke Energy Carolinas LLC	Georgia Power Co.	Alabama Power Co.	Florida Power & Light Co.	Virginia Electric & Power Co.
Foreign currency issuer credit rating	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	A/Stable/A-1	BBB+/Negative/A-2
Local currency issuer credit rating	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	A/Stable/A-1	BBB+/Negative/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31	2022-12-31	2022-12-31
Mil.	$	$	$	$	$
Revenue	7,847	11,584	7,817	17,282	9,654
EBITDA	4,176	4,586	3,173	8,247	4,655
Funds from operations (FFO)	3,642	4,002	2,688	7,487	3,999
Interest	848	831	567	880	898
Cash interest paid	595	554	364	738	710
Operating cash flow (OCF)	1,550	2,102	1,675	4,693	1,749
Capital expenditure	3,254	3,828	1,996	9,154	5,010
Free operating cash flow (FOCF)	(1,704)	(1,726)	(321)	(4,461)	(3,261)
Discretionary cash flow (DCF)	(1,754)	(3,417)	(1,635)	(6,461)	(3,261)
Cash and short-term investments	44	364	687	25	22
Gross available cash	44	364	687	25	22
Debt	17,194	20,976	10,550	22,886	19,692
Equity	15,442	18,993	11,687	38,920	17,245
EBITDA margin (%)	53.2	39.6	40.6	47.7	48.2
Return on capital (%)	8.0	7.6	10.2	9.5	8.0

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Duke Energy Carolinas LLC--Peer Comparisons

EBITDA interest coverage (x)	4.9	5.5	5.6	9.4	5.2
FFO cash interest coverage (x)	7.1	8.2	8.4	11.1	6.6
Debt/EBITDA (x)	4.1	4.6	3.3	2.8	4.2
FFO/debt (%)	21.2	19.1	25.5	32.7	20.3
OCF/debt (%)	9.0	10.0	15.9	20.5	8.9
FOCF/debt (%)	(9.9)	(8.2)	(3.0)	(19.5)	(16.6)
DCF/debt (%)	(10.2)	(16.3)	(15.5)	(28.2)	(16.6)

Business Risk

Our assessment of DEC's business risk profile reflects the company's lower-risk electric utility operations that benefit from a generally constructive regulatory framework, track record of reliable electric service, and large customer base. The company has some geographic and regulatory diversity with operations concentrated in two states (North and South Carolina). Our assessment also incorporates DEC's generation mix. As of Dec. 31, 2022, the company has about 19,492 megawatts (MW) of generation capacity, and its generation mix primarily reflects coal, nuclear, hydro, and natural gas. Coal-fired sources account for about 29% of DEC's owned generation, with nuclear, gas, and hydro sources accounting for 27%, 26%, and 17%, respectively. Our assessment of DEC's business risk also reflects both operating and environmental risks associated with its generation fleet. As DEC's parent Duke Energy executes on a clean energy transformation strategy, we think such a move could reduce DEC's environmental risk exposure over the long-term.

Financial Risk

We assess DEC's financial measures using our medial volatility table, reflecting the company's lower-risk vertically integrated electric operations and management of regulatory risk. Our base case scenario includes capital spending averaging about $3.9 billion annually through 2025. In addition, our forecast incorporates dividends to the parent averaging about $650 million through 2025. After incorporating other factors, including the company's asset retirement obligations (ARO), the North Carolina rate case, deferred fuel costs, and storm cost securitization, we expect DEC's financial measures will be in line with the significant financial risk profile category. Specifically, we expect FFO to debt of 19%-21% throughout the outlook period. Furthermore, given DEC's elevated capital spending, we expect negative discretionary flow throughout our forecast period, indicative of its external funding needs.

Debt maturities

As of Dec. 31, 2022:

- 2023: $1.018 billion
- 2024: $19 million
- 2025: $491 million
- 2026: $621 million
- 2027: $323 million
- Thereafter: $11.884 billion

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Duke Energy Carolinas LLC--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	$	$	$	$	$	$
Revenues	7,302	7,300	7,395	7,015	7,102	7,847
EBITDA	3,750	3,520	4,027	3,899	3,937	4,176
Funds from operations (FFO)	3,103	2,934	3,437	3,065	3,163	3,642
Interest expense	661	663	733	777	812	848
Cash interest paid	453	497	468	513	540	595
Operating cash flow (OCF)	2,617	2,520	2,721	2,797	2,714	1,550
Capital expenditure	2,479	2,671	2,684	2,641	2,664	3,254
Free operating cash flow (FOCF)	138	(151)	37	156	50	(1,704)
Discretionary cash flow (DCF)	(487)	(901)	(238)	(444)	(550)	(1,754)
Cash and short-term investments	16	33	18	21	7	44
Gross available cash	16	33	18	21	7	44
Debt	10,326	11,759	13,586	14,917	15,295	17,194
Common equity	11,361	11,683	12,811	13,154	13,891	15,442
Adjusted ratios						
EBITDA margin (%)	51.3	48.2	54.5	55.6	55.4	53.2
Return on capital (%)	11.5	8.4	9.5	8.3	8.5	8.0
EBITDA interest coverage (x)	5.7	5.3	5.5	5.0	4.8	4.9
FFO cash interest coverage (x)	7.8	6.9	8.4	7.0	6.9	7.1
Debt/EBITDA (x)	2.8	3.3	3.4	3.8	3.9	4.1
FFO/debt (%)	30.1	25.0	25.3	20.5	20.7	21.2
OCF/debt (%)	25.3	21.4	20.0	18.7	17.7	9.0
FOCF/debt (%)	1.3	(1.3)	0.3	1.0	0.3	(9.9)
DCF/debt (%)	(4.7)	(7.7)	(1.7)	(3.0)	(3.6)	(10.2)

Reconciliation Of Duke Energy Carolinas LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2022									
Company reported amounts	15,215	15,442	7,857	3,614	2,062	557	4,176	1,569	50	3,304
Cash taxes paid	-	-	-	-	-	-	60	-	-	-

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Reconciliation Of Duke Energy Carolinas LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Cash interest paid	-	-	-	-	-	-	(546)	-	-	-
Lease liabilities	381	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	39	4	4	(4)	35	-	-
Accessible cash and liquid investments	(44)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	50	(50)	(50)	-	(50)
Share-based compensation expense	-	-	-	34	-	-	-	-	-	-
Securitized stranded costs	(233)	-	(10)	(10)	(5)	(5)	5	(5)	-	-
Asset-retirement obligations	1,875	-	-	242	242	242	-	-	-	-
Nonoperating income (expense)	-	-	-	-	145	-	-	-	-	-
EBITDA - Gain/(loss) on disposals of PP&E	-	-	-	(4)	(4)	-	-	-	-	-
EBITDA: other income/ (expense)	-	-	-	261	261	-	-	-	-	-
D&A: Impairment charges/ (reversals)	-	-	-	-	26	-	-	-	-	-
D&A: other	-	-	-	-	(261)	-	-	-	-	-
Total adjustments	1,979	-	(10)	562	408	291	(535)	(19)	-	(50)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	17,194	15,442	7,847	4,176	2,470	848	3,642	1,550	50	3,254

Liquidity

We base our short-term 'A-2' rating on DEC on our long-term issuer credit rating. We assess the company's liquidity as adequate. We expect its liquidity sources will be more than 1.1x its uses for the next 12 months and meet its cash outflows even if its EBITDA declines by 10%. We believe the company's predictable regulatory framework provides it with cash flow stability, even in times of economic stress.

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In addition, the company has the ability to absorb high-impact, low-probability events. This reflects its $1.925 billion sublimit under parent Duke Energy's $9 billion syndicated credit facility expiring March 2028. Furthermore, it is our view that DEC could scale back its capital spending during stressful periods, which indicates its limited need for refinancing under such conditions. In addition, our assessment also reflects the company's generally prudent risk management and generally satisfactory standing in the credit markets, sufficient liquidity provided by the parent, as needed, to meet ongoing needs, and manageable debt maturities over the next few years. Overall, we believe the company will likely be able to withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations.

Principal liquidity sources

- Cash and liquid investments of $44 million as of Dec. 31, 2022;
- Credit facility availability of about $1.9 billion as of Dec. 31, 2022; and
- Cash FFO of about $3.4 billion.

Principal liquidity uses

- Current long-term and short-term debt maturities of $760 million over the next 12 months,
- Assumed maintenance capital spending of about $1.2 billion, and
- Dividends of about $100 million over the next 12 months.

Covenant Analysis

Requirements

DEC is part of Duke Energy's master credit facility. The master credit facility includes a covenant that requires DEC's total-debt-to-total-capitalization ratio to not exceed 65%.

Compliance expectations

We expect DEC to comply with the terms of its covenant agreements throughout our forecast period, even with a 10% decline in EBITDA.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	E-2	E-3	**E-4**	E-5	S-1	S-2	**S-3**	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5
- Climate transition risks - Physical risks - Waste and pollution					- Health and safety					N/A				

N/A—Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Environmental factors are a negative consideration in our credit rating analysis of DEC. As of Dec. 31, 2022, approximately 29% of the company's total electric generation fleet capacity of roughly 19,492 MW is coal based, which exposes it to potentially more stringent environmental regulations in the U.S. This exposure is partially mitigated by the parent's strategy to reach net-zero emissions by 2050. The 2021 passage of House Bill 951, which was enacted to establish a framework overseen by the North Carolina Utilities Commission (NCUC) to advance the state's carbon dioxide emission reductions plan and authorizes the use of performance-based regulation in North Carolina, provides a regulator-supported path to reduce the company's carbon emissions in North Carolina. The company's service territory is prone to severe storms and

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hurricanes. The company also faces higher coal ash risks compared to peers, and its ability to fully recover its significant coal ash costs has proved to be challenging. The company's nuclear power generation also exposes the company to potential waste, health, and safety risks.

Group Influence

Our rating on DEC incorporates our view of the company as a core subsidiary of Duke Energy, meaning that we view DEC as highly unlikely to be sold and as integral to the group's overall strategy. In addition, DEC is closely linked to Duke Energy's name and reputation, and it has strong long-term support of the group's senior management. Because we assess DEC as not sufficiently insulated from its parent, the issuer credit rating on the company is in line with Duke Energy's 'bbb+' group credit profile.

Issue Ratings--Subordination Risk Analysis

Analytical conclusions

We rate DEC's senior unsecured debt the same as our issuer credit rating on the company because it is unsecured debt of a qualifying investment-grade regulated utility. Our short-term rating on the company reflects our issuer credit rating on the company.

Issue Ratings--Recovery Analysis

Key analytical factors

We assign recovery ratings to first-mortgage bonds (FMB), which, depending on the rating category and the extent of the collateral coverage, can result in issue ratings being notched above an issuer credit rating on a utility. DEC's FMBs benefit from a first-priority lien on substantially all the utility's real property owned or subsequently acquired. Collateral coverage of over 1.5x supports a recovery rating of '1+' and an issue rating two notches above the issuer credit rating.

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Rating Component Scores

Foreign currency issuer credit rating	**BBB+/Stable/A-2**
Local currency issuer credit rating	**BBB+/Stable/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a-**

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- ARCHIVE | General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

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Related Research

Ratings Detail (as of May 08, 2023)*

Duke Energy Carolinas LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Secured	A
Senior Unsecured	BBB+
Issuer Credit Ratings History	
26-Jan-2021	BBB+/Stable/A-2
15-Dec-2020	A-/Negative/A-2
20-Nov-2019	A-/Stable/A-2
20-May-2019	A-/Negative/A-2
Related Entities	
Cinergy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Duke Energy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB-
Preferred Stock	BBB-
Senior Unsecured	BBB
Duke Energy Florida LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Secured	A
Senior Unsecured	BBB+
Duke Energy Indiana Inc.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Secured	A
Senior Unsecured	BBB+
Duke Energy Kentucky Inc.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured	BBB+
Duke Energy Ohio Inc.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Secured	A
Duke Energy Progress LLC	

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Ratings Detail (as of May 08, 2023)*

Issuer Credit Rating	BBB+/Stable/A-2
Senior Secured	A
Florida Progress Corp.	
Issuer Credit Rating	BBB+/Stable/NR
Piedmont Natural Gas Co. Inc.	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured	BBB+
Progress Energy Inc.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Unsecured	BBB

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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Volatility Recap (2022 – Q2 2023)

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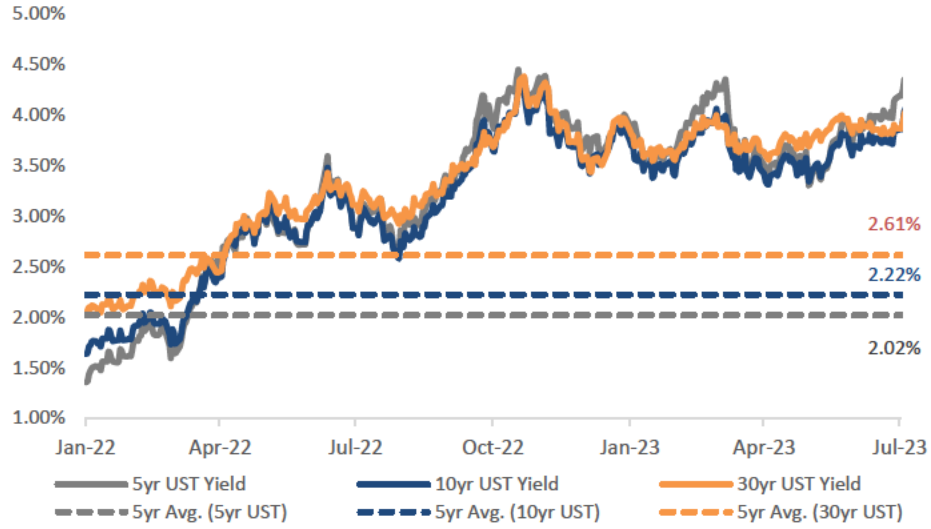
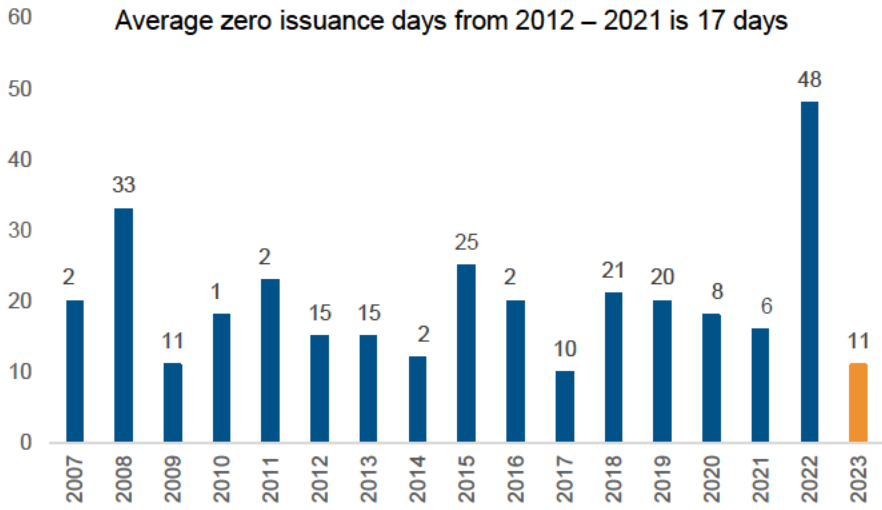
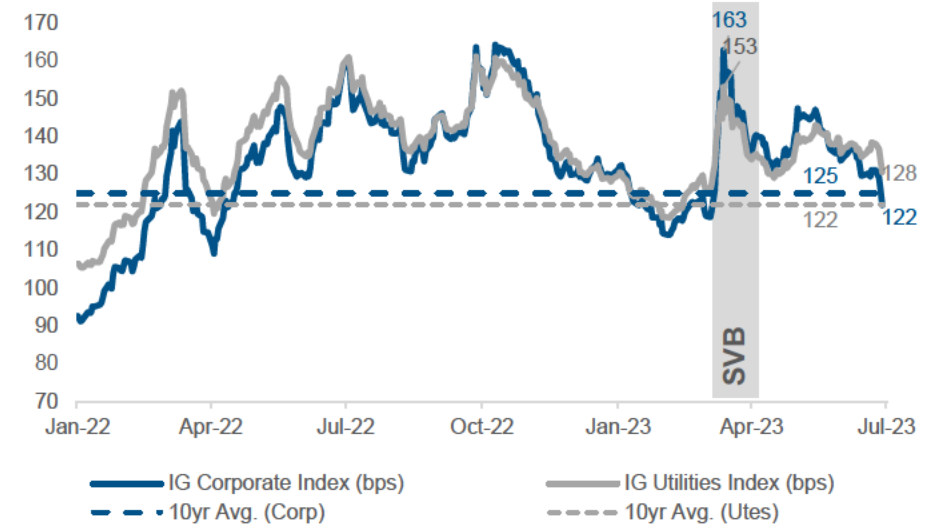
Rapid Rise in UST Rates



Record Consecutive Zero Days in March 2023*



IG Utility & Corporate Index Spreads



Source: Bloomberg, Credit Flow Research
**The number of zero days excludes Fridays and Holidays*

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Indicative New Issue Pricing

August 23, 2023

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Secondary Trading Levels: Operating Companies

Secondary Trading Levels: Operating Companies										
	Ratings				Amt	Current (bid)				
Issuer	Moody's	S&P	Coupon	Maturity	($mm)	T+	G+	S+	Yield	Price
Duke Energy Carolinas*	Aa3	A	4.950%	1/15/33	1250	+116	+114	+145	5.355%	$97.04
	Aa3	A	5.400%	1/15/54	500	+139	-	+211	5.664%	$96.18
Duke Energy Indiana*	Aa3	A	3.250%	10/1/49	500	+145	-	+207	5.724%	$66.68
	Aa3	A	5.400%	4/1/53	500	+147	-	+217	5.744%	$95.13
Duke Energy Progress*	Aa3	A	5.250%	3/15/33	500	+122	+120	+152	5.415%	$98.78
	Aa3	A	5.350%	3/15/53	500	+140	-	+210	5.674%	$95.38
Duke Energy Florida*	A1	A	2.400%	12/15/31	650	+116	+110	+143	5.355%	$80.39
	A1	A	5.950%	11/15/52	500	+145	-	+213	5.724%	$103.16
Duke Energy Ohio*	A2	A	3.650%	2/1/29	400	+90	+92	+119	5.271%	$92.43
	A2	A	5.250%	4/1/33	375	+120	+119	+150	5.395%	$98.92
	A2	A	5.650%	4/1/53	375	+153	-	+223	5.804%	$97.83
Piedmont Natural Gas	A3	BBB+	5.400%	6/15/33	350	+159	+158	+189	5.785%	$97.14
	A3	BBB+	5.050%	5/15/52	400	+179	-	+247	6.064%	$86.28
MidAmerican Energy Co*	Aa2	A+ ↓	2.700%	8/1/52	500	+128	-	+196	5.554%	$59.14
Florida Power & Light*	Aa2	A+	4.800%	5/15/33	750	+106	+105	+136	5.255%	$96.56
	Aa2	A+	5.300%	4/1/53	750	+122	-	+192	5.494%	$97.17
Northern States Power - Minnesota*	Aa3	A+	5.100%	5/15/53	800	+131	-	+201	5.584%	$93.01
DTE Electric*	Aa3	A	5.200%	4/1/33	600	+115	+114	+145	5.345%	$98.92
	Aa3	A	5.400%	4/1/53	600	+128	-	+198	5.554%	$97.77
PECO Energy*	Aa3 ↓	A ↑	4.375%	8/15/52	425	+123	-	+191	exc	$83.74
Public Service Electric & Gas*	A1	A	5.200%	8/1/33	500	+105	+105	+135	5.245%	$99.65
	A1	A	5.450%	8/1/53	400	+121	-	+192	5.484%	$99.50
San Diego Gas & Electric*	A1	A	5.350%	4/1/53	800	+145	-	+215	5.724%	$94.69
PacifiCorp*	A1 ↓	A ↓	5.500%	5/15/54	1200	+224	-	+296	6.514%	$86.60
Ameren Illinois*	A1	A	4.950%	6/1/33	500	+115	+114	+145	5.345%	$97.02
	A1	A	5.900%	12/1/52	350	+139	-	+207	5.664%	$103.32
Public Service Co of Colorado*	A1	A ↓	4.100%	6/1/32	300	+124	+120	+152	5.435%	$90.78
	A1	A ↓	5.250%	4/1/53	850	+162	-	+232	5.894%	$91.03
Commonwealth Edison Co*	A1	A	4.900%	2/1/33	400	+107	+105	+136	5.265%	$97.31
	A1	A	5.300%	2/1/53	575	+130	-	+200	5.574%	$96.06
Oncor Electric Delivery Co*	A2	A+	4.550%	9/15/32	700	+116	+113	+145	5.355%	$94.28
	A2	A+	4.950%	9/15/52	900	+130	-	+199	5.574%	$91.07
CenterPoint Houston Electric*	A2	A	4.950%	4/1/33	600	+113	+112	+143	5.325%	$97.21
	A2	A	5.300%	4/1/53	300	+124	-	+194	5.514%	$96.89
Ameren Missouri*	A2	A	2.150%	3/15/32	525	+117	+112	+145	5.365%	$78.17
	A2	A	5.450%	3/15/53	500	+140	-	+210	5.674%	$96.81
Entergy Louisiana*	A2	A	2.350%	6/15/32	500	+131	+127	+159	5.505%	$78.21
	A2	A	4.750%	9/15/52	500	+148	-	+217	5.754%	$85.91
Entergy Arkansas*	A2	A	5.300%	9/15/33	300	+125	+125	+156	5.445%	$98.88
	A2	A	3.350%	6/15/52	400	+139	-	+207	5.664%	$67.32
East Ohio Gas Co	A2	BBB+ ↓	2.000%	6/15/30	500	+154	+142	+175	5.735%	$79.20
	A2	BBB+ ↓	3.000%	6/15/50	800	+173	-	+237	6.004%	$60.21
Con Edison Co of NY	Baa1 ↑	A-	5.200%	3/1/33	500	+123	+121	+153	5.425%	$98.34
	Baa1 ↑	A-	6.150%	11/15/52	700	+154	-	+222	5.814%	$104.66

↓ negative outlook ⇓ negative watch ⇔watch developing ↔ outlook forming ↑ positive outlook ⇑ positive watch *secured

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New Issue Pricing: Operating Companies

Indicative New Issue Levels							
Duke Energy Carolinas - First Mortgage Bonds (Aa3 / A; Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Benchmark Treasury	4.657%	4.371%	4.306%	4.195%	4.195%	4.483%	4.270%
Re-offer Spread (bps)	**+65 - 70**	**+85 - 90**	**+105 - 110**	**+120 - 125**	**+130 - 135**	**+125 area**	**+145 area**
Re-offer Yield	5.31% - 5.36%	5.22% - 5.27%	5.36% - 5.41%	5.40% - 5.45%	5.50% - 5.55%	5.73% area	5.72% area
Swapped Spread to SOFR (bps)	SOFR+ 81 - 86	SOFR+ 107 - 112	SOFR+ 134 - 139	SOFR+ 147 - 152	SOFR+ 160 - 165	SOFR+ 190 area	SOFR+ 212 area
Duke Energy Progress - First Mortgage Bonds (Aa3 / A; Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Re-offer Spread (bps)	**+65 - 70**	**+85 - 90**	**+105 - 110**	**+120 - 125**	**+130 - 135**	**+125 area**	**+145 area**
Re-offer Yield	5.31% - 5.36%	5.22% - 5.27%	5.36% - 5.41%	5.40% - 5.45%	5.50% - 5.55%	5.73% area	5.72% area
Swapped Spread to SOFR (bps)	SOFR+ 81 - 86	SOFR+ 107 - 112	SOFR+ 134 - 139	SOFR+ 147 - 152	SOFR+ 160 - 165	SOFR+ 190 area	SOFR+ 212 area
Duke Energy Ohio - First Mortgage Bonds (A2 / A; Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Re-offer Spread (bps)	**+75 - 80**	**+95 - 100**	**+115 - 120**	**+130 - 135**	**+140 - 145**	**+135 area**	**+155 area**
Re-offer Yield	5.41% - 5.46%	5.32% - 5.37%	5.46% - 5.51%	5.50% - 5.55%	5.60% - 5.65%	5.83% area	5.82% area
Swapped Spread to SOFR (bps)	SOFR+ 91 - 96	SOFR+ 117 - 122	SOFR+ 144 - 149	SOFR+ 157 - 162	SOFR+ 170 - 175	SOFR+ 200 area	SOFR+ 222 area
Duke Energy Indiana - First Mortgage Bonds (Aa3 / A; Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Re-offer Spread (bps)	**+75 - 80**	**+95 - 100**	**+115 - 120**	**+130 - 135**	**+140 - 145**	**+135 area**	**+155 area**
Re-offer Yield	5.41% - 5.46%	5.32% - 5.37%	5.46% - 5.51%	5.50% - 5.55%	5.60% - 5.65%	5.83% area	5.82% area
Swapped Spread to SOFR (bps)	SOFR+ 91 - 96	SOFR+ 117 - 122	SOFR+ 144 - 149	SOFR+ 157 - 162	SOFR+ 170 - 175	SOFR+ 200 area	SOFR+ 222 area
Duke Energy Florida - First Mortgage Bonds (A1 / A; Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Re-offer Spread (bps)	**+70 - 75**	**+90 - 95**	**+110 - 115**	**+125 - 130**	**+135 - 140**	**+130 area**	**+150 area**
Re-offer Yield	5.36% - 5.41%	5.27% - 5.32%	5.41% - 5.46%	5.45% - 5.50%	5.55% - 5.60%	5.78% area	5.77% area
Swapped Spread to SOFR (bps)	SOFR+ 86 - 91	SOFR+ 112 - 117	SOFR+ 139 - 144	SOFR+ 152 - 157	SOFR+ 165 - 170	SOFR+ 195 area	SOFR+ 217 area
Piedmont Natural Gas - Senior Unsecured Notes (A3 / BBB+; Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Re-offer Spread (bps)	**+100 - 105**	**+125 - 130**	**+140 - 145**	**+160 - 165**	**+170 - 175**	**+170 - 175**	**+190 - 195**
Re-offer Yield	5.66% - 5.71%	5.62% - 5.67%	5.71% - 5.76%	5.80% - 5.85%	5.90% - 5.95%	6.18% - 6.23%	6.17% - 6.22%
Swapped Spread to SOFR (bps)	SOFR+ 116 - 121	SOFR+ 147 - 152	SOFR+ 169 - 174	SOFR+ 187 - 192	SOFR+ 200 - 205	SOFR+ 235 - 240	SOFR+ 257 - 262

Benchmark Treasury and SOFR rates as of 8/23/2023

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Secondary Trading Levels and New Issue Pricing: Holdco

Secondary Trading Levels: Holding Companies											
	Ratings					Amt	Current (bid)				
Issuer	Moody's		S&P		Coupon	Maturity	($mm)	T+	G+	S+	Yield	Price
Duke Energy	Baa2		BBB		5.000%	12/8/25	500	+63	+74	+92	5.601%	$98.72
	Baa2		BBB		5.000%	12/8/27	500	+103	+94	+120	5.401%	$98.48
	Baa2		BBB		4.500%	8/15/32	1150	+148	+144	+177	5.675%	$91.83
	Baa2		BBB		3.300%	6/15/41	750	+158	+164	+224	6.063%	$70.15
	Baa2		BBB		5.000%	8/15/52	1150	+176	-	+244	6.034%	$85.93
Progress Energy	Baa1		BBB		6.000%	12/1/39	600	+187	+197	+251	6.353%	$96.44
Berkshire Hathaway Energy	A3		A-	↓	1.650%	05/15/31	500	+130	+122	+155	5.495%	$76.06
	A3		A-	↓	4.600%	05/01/53	1000	+174	-	+244	6.014%	$80.53
Public Service Enterprise Group	Baa2		BBB		5.850%	11/15/27	700	+110	+98	+125	5.471%	$101.38
	Baa2		BBB		2.450%	11/15/31	750	+149	+143	+176	5.685%	$78.98
Xcel Energy	Baa1		BBB+		1.750%	3/15/27	500	+110	+90	+114	5.471%	$88.12
	Baa1		BBB+		5.450%	8/15/33	800	+165	+165	+196	5.845%	$97.04
Eversource Energy	Baa1	↓	BBB+	↑	5.450%	3/1/28	1300	+110	+104	+130	5.471%	$99.92
	Baa1	↓	BBB+	↑	5.125%	5/15/33	800	+148	+147	+178	5.675%	$95.93
	Baa1	↓	BBB+	↑	3.450%	1/15/50	650	+153	-	+216	5.804%	$68.40
WEC Energy	Baa1		BBB+	↓	4.750%	1/9/26	1000	+95	+77	+95	5.607%	$98.11
	Baa1		BBB+	↓	4.750%	1/15/28	450	+112	+104	+130	5.491%	$97.14
NextEra Energy Capital Holdings	Baa1		BBB+		4.900%	2/28/28	1250	+114	+108	+134	5.511%	$97.59
	Baa1		BBB+		5.050%	2/28/33	1000	+143	+141	+173	5.625%	$95.81
	Baa1		BBB+		5.250%	2/28/53	1150	+167	-	+237	5.944%	$90.40
Ameren Corporation	Baa1		BBB		1.950%	3/15/27	500	+105	+85	+109	5.421%	$88.91
	Baa1		BBB		3.500%	1/15/31	800	+140	+131	+164	5.595%	$87.46
American Electric Power	Baa2		BBB+		5.750%	11/1/27	500	+100	+88	+114	5.371%	$101.38
	Baa2		BBB+		5.625%	3/1/33	850	+154	+152	+184	5.735%	$99.20
	Baa2		BBB+		3.250%	3/1/50	400	+165	-	+228	5.924%	$64.46
NiSource Inc.	Baa2		BBB+		5.250%	3/30/28	1050	+115	+110	+136	5.521%	$98.91
	Baa2		BBB+		5.400%	6/30/33	450	+144	+144	+174	5.635%	$98.23
	Baa2		BBB+		5.000%	6/15/52	350	+175	-	+243	6.024%	$86.07
Southern Company	Baa2		BBB	↑	4.850%	6/15/28	750	+105	+103	+128	5.421%	$97.60
	Baa2		BBB	↑	5.200%	6/15/33	750	+148	+147	+178	5.675%	$96.45
	Baa2		BBB	↑	4.400%	7/1/46	2000	+148	-	+223	5.963%	$80.62
Exelon Corporation	Baa2		BBB	↑	5.150%	3/15/28	1000	+107	+101	+127	5.441%	$98.84
	Baa2		BBB	↑	5.300%	3/15/33	850	+148	+146	+178	5.675%	$97.26
	Baa2		BBB	↑	5.600%	3/15/53	650	+171	-	+241	5.984%	$94.70
Dominion Energy	Baa2		BBB	↓	1.450%	4/15/26	563	+92	+82	+101	5.577%	$90.00
	Baa2		BBB	↓	5.375%	11/15/32	850	+156	+153	+185	5.755%	$97.30
	Baa2		BBB	↓	3.300%	4/15/41	465	+156	+162	+222	6.043%	$70.48
	Baa2		BBB	↓	4.850%	8/15/52	600	+174	-	+242	6.014%	$84.12
Sempra Energy	Baa2		BBB		5.400%	8/1/26	550	+100	+99	+119	5.657%	$99.30
	Baa2		BBB		5.500%	8/1/33	700	+164	+164	+194	5.835%	$97.48

↓ negative outlook ⇓ negative watch ⇔watch developing ↔ outlook forming ↑ positive outlook ⇑ positive watch *secured

Indicative New Issue Levels							
Duke Energy - Senior Notes (Baa2 / BBB / BBB+; Stable / Stable / Stable)							
Fixed Rate	**3-year**	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**	**30-year**
Benchmark Treasury	4.657%	4.371%	4.306%	4.195%	4.195%	4.483%	4.270%
Re-offer Spread (bps)	**+95 - 100**	**+120 - 125**	**+135 - 140**	**+155 - 160**	**+165 - 170**	**+165 - 170**	**+185 - 190**
Re-offer Yield	5.61% - 5.66%	5.57% - 5.62%	5.66% - 5.71%	5.75% - 5.80%	5.85% - 5.90%	6.13% - 6.18%	6.12% - 6.17%
Swapped Spread to SOFR (bps)	SOFR+ 111 - 116	SOFR+ 142 - 147	SOFR+ 164 - 169	SOFR+ 182 - 187	SOFR+ 192 - 197	SOFR+ 230 - 235	SOFR+ 252 - 257

Benchmark Treasury and SOFR rates as of 8/23/2023

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I/A

JAMES M. COYNE
SENIOR VICE PRESIDENT

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before federal, state and provincial jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University and an M.S. in Resource Economics from the University of New Hampshire.

AREAS OF EXPERTISE

Energy Regulation

- Rate policy
- Cost of capital
- Incentive regulation
- Fuels and power markets

Management and Business Strategy

- Fuels and power market assessments
- Investment feasibility
- Corporate and business unit planning
- Benchmarking and productivity analysis

Financial and Economic Advisory

- Valuation analysis
- Due diligence
- Buy and sell-side advisory

Litigation Support and Expert Testimony

- Rate and regulatory policy
- Fuels and power markets
- Contract litigation
- Valuation and damages

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PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations
Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

University of New Hampshire
M.S., Resource Economics, *with honors*, 1981

Georgetown University
B.S., Business Administration and Economics, *cum laude*, 1975

DESIGNATIONS AND AFFILIATIONS

Community Rowing Inc., Board of Directors, 2015 - 2019

Georgetown University, Alumni Admissions Interviewer, 1988 – current

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001

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American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996

National Petroleum Council, Regulatory and Policy Task Forces, 1992

President, International Association for Energy Economics, Dallas Chapter, 1995

Gas Research Institute, Economics Advisory Committee, 1990-1993

NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984

PUBLICATIONS AND RESEARCH

"Advancing FERC's Methodology for Determining Allowed ROEs for Electric Transmission Companies," submitted to FERC on behalf of EEI, James Coyne, Joshua Nowak and Julie Lieberman, May, 2020.

"Regulator Rationale for Ratepayer-Funded Electricity and Natural Gas Innovation", James M. Coyne, Robert C. Yardley, Jr. and Jessalyn G. Pryciak, Energy Regulation Quarterly, Volume 6, Issue 3, 2018.

"Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May 2015.

"Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010

"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June 2007

"Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006

"Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004

"Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003

"The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001

Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992

"Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

"The Market Risk Premium: An In-Depth Review", Society of Utility and Regulatory Financial Analysts 53rd Financial Forum, Richmond, VA, April 28,2022

"Energy Sector in Transition", Ontario Energy Association, Toronto, ON, September 24, 2018.

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"Understanding Regulated Utilities in Today's Capital Markets", NARUC Annual Meeting, La Quinta, CA, November 14, 2016.

"Rate of Return: Where the Regulatory Rubber Meets the Road," CAMPUT Annual Conference, Montreal, Quebec, May 17, 2016.

"Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

"M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010

"The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010

"A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008

"Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005

"The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005

"Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005

"The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005

"Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002

"Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001

"Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001

"Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999

"New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999

"Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998

"Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

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SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Alberta Beverage Container Management Board				
Alberta Beverage Container Management Board	2016 2019	Expert for the Board	N/A	Return Margin on Bottle Depots
Alberta Utilities Commission				
ATCO Utilities Group	2008 2009	ATCO Gas; ATCO Pipelines Ltd.; ATCO Electric Ltd.	Application No. 1578571 / Proceeding ID. 85	2009 Generic Cost of Capital Proceeding (Gas & Electric)
Enmax Power Corporation	2017	Enmax	22570	Cost of Common Equity
Enmax Power Corporation	2020	Enmax	24110	2021 Generic Cost of Capital
Enmax Power Corporation	2023	Enmax	27084	2024 and Beyond Cost of Capital Parameters
American Arbitration Association				
TransCanada Corporation	2004	TransCanada Corporation	AAA Case No. 50T 1810018804	Valuation of Natural Gas Pipeline
British Columbia Utilities Commission				
FortisBC	2012	FortisBC Utilities	G-20-12	Cost of Capital Adjustment Mechanisms
FortisBC	2015 2016	FortisBC Utilities	G-129-16	Cost of Capital (Gas and Electric Distribution)
FortisBC	2022	FortisBC Utilities	G-217-22	Cost of Capital (Gas and Electric Distribution)
California Public Utilities Commission				
San Diego Gas & Electric Company	2019	San Diego Gas & Electric Company	A-19-04-014	Cost of Capital (Electric & Gas Distribution)
San Diego Gas & Electric Company	2021	San Diego Gas & Electric Company	A-21-08-014	Cost of Capital (Electric & Gas Distribution)
Southern California Gas Company	2022	Southern California Gas Company	A-22-04-011	Cost of Capital (Gas Distribution)
San Diego Gas & Electric Company	2022	San Diego Gas & Electric Company	A-22-04-012	Cost of Capital (Electric & Gas Distribution)
Canada Energy Regulator				
Enbridge Pipelines Inc.	2021	Enbridge Pipelines Inc.	RH-001-2020	Cost of Capital (Oil Pipeline)
Connecticut Department of Public Utility Control				
Aquarion Water Company of CT/ Macquarie Securities	2007	Aquarion Water Company of CT	DPUC Docket No. 07-05-19	Return on Equity (Water)

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SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Federal Energy Regulatory Commission				
Atlantic Power Corporation	2007	Atlantic Path 15, LLC	ER08-374-000	Return on Equity (Electric)
Atlantic Power Corporation	2010	Atlantic Path 15, LLC	ER11-2909-000	Return on Equity (Electric)
Atlantic Power Corporation	2011	Atlantic Path 15, LLC	ER11-2909 and EL11-29	Rate of Return (Electric Transmission)
Startrans IO, LLC	2012	Startrans IO, LLC	ER-13-272-000	Cost of Capital (Electric Transmission)
Startrans IO, LLC	2015	Startrans IO, LLC	ER-16-194-000 and EL16-25-000	Cost of Capital (Electric Transmission)
Northern States Power Company	2019	Northern States Power Company	ER20-26-000	Cost of Capital (Electric Transmission)
PPL Electric Utilities Corp.	2020	PP&l Industrial Customer Alliance v. PPL Electric	EL20-48-000	Answering Testimony in Response to a Section 206 ROE Complaint
South First Energy Operating Companies	2020	South First Energy Operating Companies	ER21-253-000	Cost of Capital (Electric Transmission)
DCR Transmission, L.L.C.	2023	DCR Transmission, L.L.C.	ER23-___-000	Cost of Capital (Electric Transmission)
Florida Public Service Commission				
Florida Power & Light Company	2021	Florida Power & Light Company	Docket No. 20210015-EI	Cost of Capital (Electric)
Georgia Public Service Commission				
Georgia Power Company	2022	Georgia Power Company	44280	Cost of Capital (Electric)
Hawaii Public Utility Commission				
The Gas Company	2017	The Gas Company	Docket No. 2017-0105	Cost of Capital (Gas Distribution)
Maine Public Utilities Commission				
Bangor Hydro Electric Company	1998	Bangor Hydro Electric Company	MPUC Docket No. 98-820	Transaction-Related Financial Advisory Services, Valuation
Central Maine Power Company	2007	Central Maine Power Company	MPUC Docket No. 2007-215	Sales Forecast
Enmax Corporation	2019	Enmax Corporation	2019-00097	Regulatory Approval of Emera Maine Acquisition

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SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Versant Power	2021	Versant Power	MPUC Docket No. 2020-00316	Cost of Capital (Electric)
Versant Power	2022	Versant Power	2022-00XXX	Cost of Capital (Electric)
Maryland State Board of Contract Appeals				
Green Planet Power Solutions	2018	Green Planet Power Solutions and Maryland Bio Energy LLC v. Maryland Department of General Services	MSBCA 3061	Contract Litigation, Power Purchase Agreement, Damages Analysis
Massachusetts Superior Court				
Burncoat Pond Watershed District	2010	Central Water District v. Burncoat Pond Watershed District	WDCV 2001-0105	Valuation/Eminent Domain
Minnesota Public Utilities Commission				
Northern States Power Company	2015 2016	Northern States Power Company	E-002-GR-15-826	Cost of Capital (Electric)
Northern States Power Company	2017	Northern States Power Company	E002/M-17-797 G002/M-17-787 E002/M-17-818	Cost of Capital (Electric and Gas Rate Riders for Transmission, Renewable Generation and Gas Distribution)
New Brunswick Energy and Utilities Board				
Liberty Utilities (Gas New Brunswick) LP	2021	Liberty Utilities (Gas New Brunswick) LP	491	Cost of Capital (Gas)
Newfoundland and Labrador Board of Commissioners of Public Utilities				
Newfoundland Power	2016	Newfoundland Power	2016 GRA	Cost of Capital (Electric)
Newfoundland Power	2018	Newfoundland Power	2018 GRA	Cost of Capital (Electric)
Newfoundland Power	2021	Newfoundland Power	2021 GRA	Cost of Capital (Electric)
New Jersey Board of Public Utilities				
Conectiv	2000-2001	Atlantic City Electric Company	NJBPU Docket No. EM00020106	Transaction-Related Financial Advisory Services

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SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Nova Scotia Utility and Review Board				
Nova Scotia Power Inc.	2012	Nova Scotia Power Inc.	2013 GRA	Return on Equity/Business Risk (Electric)
Nova Scotia Power Inc.	2022	Nova Scotia Power Inc.	2022 GRA	Return on Equity/Business Risk (Electric)
Eastward Energy Inc.	2023	Eastward Energy Inc.	M10960	Return on Equity/Business Risk (Gas)
Ontario Energy Board				
Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	2009	Enbridge Gas Distribution and Hydro One Networks and the Coalition of Large Distributors	EB-2009-0084	Ontario Energy Board's 2009 Consultative Process on Cost of Capital Review (Gas & Electric)
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study and Cost of Capital (Gas Distribution)
Enbridge Gas Distribution	2014	Enbridge Gas Distribution	EB-2012-0459	Incentive Regulation Plan and Industry Productivity Study
Ontario Power Generation	2016	Ontario Power Generation	EB-2016-0152	Cost of Capital (Electric Generation)
Ontario Power Generation	2020	Ontario Power Generation	EB-2020-0290	Capital Structure (Electric Generation)
Enbridge Gas Distribution	2022	Enbridge Gas Distribution	EB-2022-0200	Capital Structure and Business Risk
Prince Edward Island Regulatory and Appeals Commission				
Maritime Electric Company	2015	Maritime Electric Company	UE20942	Return on Capital (Electric)
Maritime Electric Company	2022	Maritime Electric Company	UE20946	Return on Capital (Electric)
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	2022	Duke Energy Ohio, Inc.	2022-00372	Cost of Capital (Gas Distribution)
Duke Energy Ohio, Inc.	2023	Duke Energy Ohio, Inc.	22-507-GA-AIR	Cost of Capital (Gas)
Régie de l'énergie du Québec				
Gaz Métro	2012	Gaz Métro	R-3809-2012	Return on Equity/Business Risk/ Capital Structure (Gas Distribution)

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SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2013	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3842-2013	Return on Equity/Business Risk (Electric)
Hydro-Québec Distribution	2014	Hydro-Québec Distribution	R-3905-2014	Remuneration of Deferral Accounts
Hydro-Québec Distribution and Hydro- Québec TransÉnergie	2015-2017	Hydro-Québec Distribution and Hydro- Québec TransÉnergie	R-3897-2014	Performance-Based Ratemaking
South Carolina Public Service Commission				
Piedmont Natural Gas Company	2022	Piedmont Natural Gas Company	2022-89-G	Return on Equity (Gas Distribution)
Duke Energy Progress	2022	Duke Energy Progress	Docket No. 2022-254-E	Return on Equity (Electric)
South Dakota Public Service Commission				
Northern States Power Company-MN	2012	Northern States Power Company-MN	EL 11-019	Return on Equity
Texas Public Utility Commission				
Texas New Mexico Power Company	2004	Texas New Mexico Power Company	PUC Docket No. 29206	Auction Process and Stranded Cost Recovery
U.S. Department of Commerce				
Government of Québec	2017	Duty Investigation of Uncoated Groundwood Paper from Canada	PUC Docket No. 29206	Contracting for Renewable Resources, Market Analysis, Damages Analysis
Vermont Public Service Board				
Vermont Gas Systems, Inc.	2006	Vermont Gas Systems, Inc.	VPSB Docket No. 7109	Models of Incentive Regulation
Vermont Gas Systems, Inc.	2012	Vermont Gas Systems, Inc.	Docket No. 7803A	Cost of Capital (Gas Distribution)
Green Mountain Power Corporation	2013	Green Mountain Power Corporation	Docket No. 8191	Return on Equity (Electric)
Vermont Gas Systems, Inc.	2016	Vermont Gas Systems, Inc.	Docket No. 8698/8710	Return on Equity (Gas Distribution)
Green Mountain Power Corporation	2017	Green Mountain Power Corporation	Docket No. Tariff-8677	Return on Equity (Electric)
Green Mountain Power Corporation	2018	Green Mountain Power Corporation	18-0974	Return on Equity (Electric)

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SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
State Corporation of Virginia				
Dominion Energy Virginia	2021	Virginia Electric and Power Company	PUR-2021-00058	Cost of Capital (Electric)
Wisconsin Public Service Commission				
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-170	Return on Equity (Electric)
Wisconsin Power and Light Company	2007	Wisconsin Power and Light Company	PSCW Docket No. 6680-CE-171	Return on Equity (Electric)
Northern States Power Company	2011	Northern States Power Company	PSCW Docket No. 4220-UR-117	Return on Equity (Electric)
Northern States Power Company	2013	Northern States Power Company	PSCW Docket No. 4220-UR-119	Return on Equity (Gas & Electric)
Northern States Power Company	2015	Northern States Power Company	PSCW Docket No. 4220-UR-121	Return on Equity (Gas & Electric)
Northern States Power Company	2017 2019	Northern States Power Company	PSCW Docket No. 4220-UR-123, 4220-UR-124	Return on Equity (Gas & Electric)
Northern States Power Company	2021	Northern States Power Company	4220-UR-125	Cost of Capital (Electric, Affidavit)
Northern States Power Company	2023	Northern States Power Company	4220-UR-126	Cost of Capital (Electric & Gas)
Yukon Utilities Board				
ATCO Electric Yukon	2016	ATCO Electric Yukon	2016-2017 GRA	Return on Equity (Electric)

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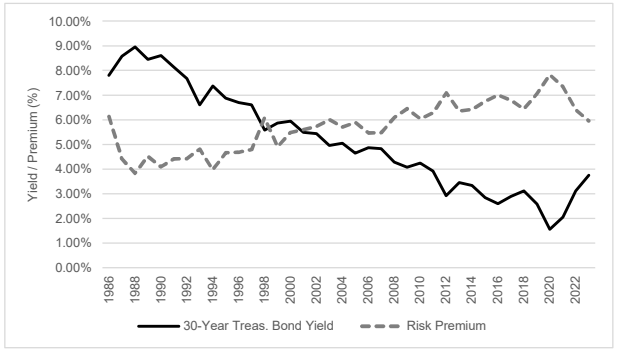
RISK PREMIUM ANALYSIS APPLYING MR. WALTERS' DATA
Risk Premium - 30-Year Treasury Yield

Risk Premium Data

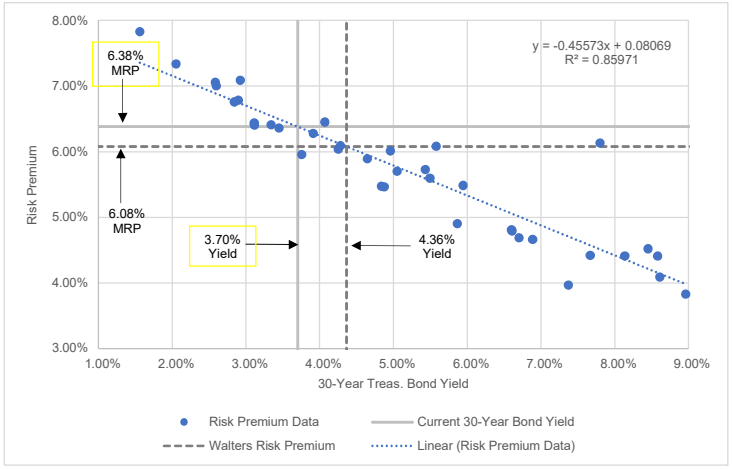
Year	Auth. ROE	30-Year Treas. Bond Yield	Risk Premium
1986	13.93%	7.80%	6.13%
1987	12.99%	8.58%	4.41%
1988	12.79%	8.96%	3.83%
1989	12.97%	8.45%	4.52%
1990	12.70%	8.61%	4.09%
1991	12.55%	8.14%	4.41%
1992	12.09%	7.67%	4.42%
1993	11.41%	6.60%	4.81%
1994	11.34%	7.37%	3.97%
1995	11.55%	6.88%	4.67%
1996	11.39%	6.70%	4.69%
1997	11.40%	6.61%	4.79%
1998	11.66%	5.58%	6.08%
1999	10.77%	5.87%	4.90%
2000	11.43%	5.94%	5.49%
2001	11.09%	5.49%	5.60%
2002	11.16%	5.43%	5.73%
2003	10.97%	4.96%	6.01%
2004	10.75%	5.05%	5.70%
2005	10.54%	4.65%	5.89%
2006	10.34%	4.87%	5.47%
2007	10.31%	4.83%	5.48%
2008	10.37%	4.28%	6.09%
2009	10.52%	4.07%	6.45%
2010	10.29%	4.25%	6.04%
2011	10.19%	3.91%	6.28%
2012	10.01%	2.92%	7.09%
2013	9.81%	3.45%	6.36%
2014	9.75%	3.34%	6.41%
2015	9.60%	2.84%	6.76%
2016	9.60%	2.60%	7.00%
2017	9.68%	2.90%	6.79%
2018	9.55%	3.11%	6.44%
2019	9.64%	2.58%	7.06%
2020	9.39%	1.56%	7.83%
2021	9.39%	2.05%	7.34%
2022	9.52%	3.12%	6.41%
2023	9.71%	3.75%	5.96%

Source: Exhibit CCW-10



RISK PREMIUM ANALYSIS APPLYING MR. WALTERS' DATA
Risk Premium - 30-Year Treasury Yield

Linear Regression Analysis



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.92720744
R Square	0.859713637
Adjusted R Square	0.855816794
Standard Error	0.003875984
Observations	38

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0033144	0.0033144	220.6179588	6.28099E-17
Residual	36	0.000540837	1.50233E-05		
Total	37	0.003855237			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.080685772	0.001701042	47.43313816	4.72545E-34	0.077235898	0.084135646	0.077235898	0.084135646
30-Year Treas. Bond Yield	-0.45572702	0.030682048	-14.85321375	6.28099E-17	-0.517953098	-0.393500942	-0.517953098	-0.393500942

	Yield	Risk Premium	**ROE**
Projected 30-Year Treasury Yield	*3.70%*	6.38%	**10.08%**
Implied Yield at 6.08% Risk Premium	4.36%	*6.08%*	**10.44%**

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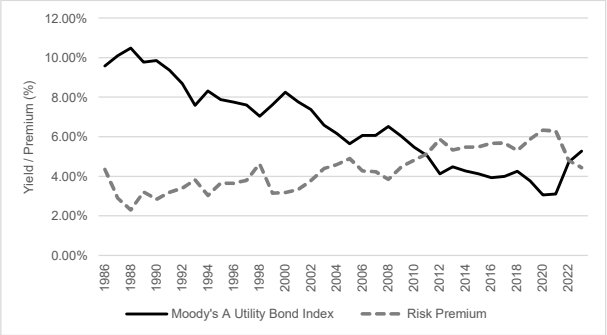
RISK PREMIUM ANALYSIS APPLYING MR. WALTERS' DATA
Risk Premium - Moody's A Utility Bond Yield

Risk Premium Data

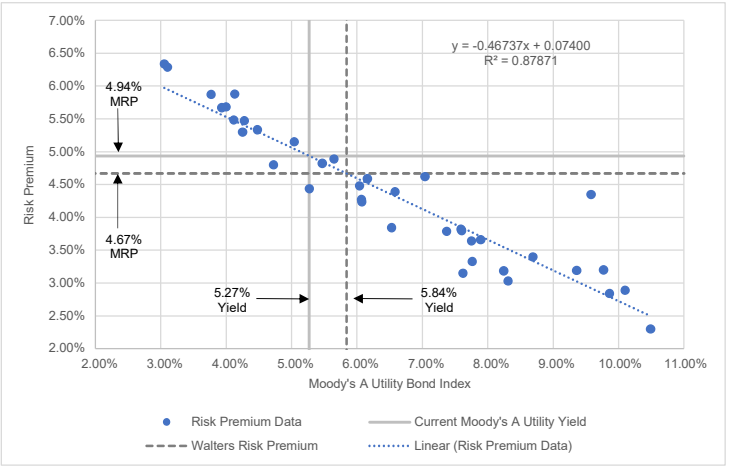
Year	Auth. ROE	Moody's A Utility Bond Index	Risk Premium
1986	13.93%	9.58%	4.35%
1987	12.99%	10.10%	2.89%
1988	12.79%	10.49%	2.30%
1989	12.97%	9.77%	3.20%
1990	12.70%	9.86%	2.84%
1991	12.55%	9.36%	3.19%
1992	12.09%	8.69%	3.40%
1993	11.41%	7.59%	3.82%
1994	11.34%	8.31%	3.03%
1995	11.55%	7.89%	3.66%
1996	11.39%	7.75%	3.64%
1997	11.40%	7.60%	3.80%
1998	11.66%	7.04%	4.62%
1999	10.77%	7.62%	3.15%
2000	11.43%	8.24%	3.19%
2001	11.09%	7.76%	3.33%
2002	11.16%	7.37%	3.79%
2003	10.97%	6.58%	4.39%
2004	10.75%	6.16%	4.59%
2005	10.54%	5.65%	4.89%
2006	10.34%	6.07%	4.27%
2007	10.31%	6.07%	4.24%
2008	10.37%	6.53%	3.84%
2009	10.52%	6.04%	4.48%
2010	10.29%	5.47%	4.82%
2011	10.19%	5.04%	5.15%
2012	10.01%	4.13%	5.88%
2013	9.81%	4.48%	5.33%
2014	9.75%	4.28%	5.47%
2015	9.60%	4.12%	5.48%
2016	9.60%	3.93%	5.67%
2017	9.68%	4.00%	5.68%
2018	9.55%	4.25%	5.30%
2019	9.64%	3.77%	5.87%
2020	9.39%	3.05%	6.34%
2021	9.39%	3.10%	6.29%
2022	9.52%	4.72%	4.80%
2023	9.71%	5.27%	4.44%

Source: Exhibit CCW-11



RISK PREMIUM ANALYSIS APPLYING MR. WALTERS' DATA
Risk Premium - Moody's A Utility Bond Yield

Linear Regression Analysis



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.937394831
R Square	0.87870907
Adjusted R Square	0.875339877
Standard Error	0.003749533
Observations	38

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.003666685	0.003666685	260.8070234	4.53102E-18
Residual	36	0.000506124	1.4059E-05		
Total	37	0.004172809			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.073999915	0.001982316	37.3300205	2.2181E-30	0.069979591	0.078020239	0.069979591	0.078020239
Moody's A Utility Bond Index	-0.46736913	0.028940124	-16.14952084	4.53102E-18	-0.526062422	-0.408675839	-0.526062422	-0.408675839

	Yield	Risk Premium	**ROE**
13-Week Average Moody's A Utility Bond Index	*5.27%*	4.94%	**10.21%**
26-Week Average Moody's A Utility Bond Index	*5.28%*	4.93%	**10.21%**
13-Week Average Moody's Baa Utility Bond Index	*5.61%*	4.78%	**10.39%**
26-Week Average Moody's Baa Utility Bond Index	*5.59%*	4.79%	**10.38%**
Implied Yield at 4.67% Risk Premium	5.84%	*4.67%*	**10.51%**

Source: Yields reported in Exhibit CCW-13

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COMPARISON OF PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

		[1]			[2]		[3]				[4]
							Decoupling		New Capital		
Proxy Group Company	TICKER	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure	CWIP in Rate Base
Alliant Energy Corporation	LNT	Iowa	Electric	1	Historical	Average					No
	LNT	Iowa	Gas	1	Historical	Average					No
	LNT	Wisconsin	Electric	1	Fully Forecast	Average					Rider
	LNT	Wisconsin	Gas	1	Fully Forecast	Average					Rider
Ameren Corporation	AEE	Illinois	Electric	1	Fully Forecast	Average					Partial
	AEE	Illinois	Gas	1	Fully Forecast	Average		x		x	Partial
	AEE	Missouri	Electric	1	Partially Forecast	Year End		x		x	No
	AEE	Missouri	Gas	1	Partially Forecast	Year End		x		x	No
American Electric Power Company, Inc.	AEP	Arkansas	Electric	1	Partially Forecast	Year End		x	x		No
	AEP	Indiana	Electric	1	Historical	Year End		x		x	Partial
	AEP	Kentucky	Electric	1	Historical	Year End		x			Yes
	AEP	Louisiana	Electric	1	Historical	Average		x			Partial
	AEP	Michigan	Electric	1	Fully Forecast	Average					Yes
	AEP	Ohio	Electric	1	Partially Forecast	Year End		x		x	Partial
	AEP	Oklahoma	Electric	1	Historical	Year End		x		x	Yes
	AEP	Tennessee	Electric	1	Fully Forecast	Average					Yes
	AEP	Texas	Electric	1	Historical	Year End				x	No
	AEP	Texas	Electric	1	Historical	Year End				x	No
	AEP	Virginia	Electric	1	Historical	Year End			x		No
	AEP	West Virginia	Electric	1	Historical	Average					No (large projects may be allowed)
Avista Corporation	AVA	Washington	Electric	1	Historical	Year End		x			
	AVA	Washington	Gas	1	Historical	Year End		x			
	AVA	Idaho	Electric	1	Historical	Year End	x				No
	AVA	Idaho	Gas	1	Historical	Year End	x				No
	AVA	Oregon	Gas	1	Fully Forecast	Average	x				No
Black Hills Corporation	BKH	South Dakota	Electric	1	Historical	Average		x			Rider
	BKH	Wyoming	Electric	1	Historical	Year End		x			No
	BKH	Colorado	Electric	1	Historical	Average			x	x	Partial
CenterPoint Energy Inc.	CNP	Indiana	Electric	1	Historical	Year End		x		x	Partial
	CNP	Indiana	Gas	1	Historical	Year End	x			x	Partial
	CNP	Louisiana	Gas	1	Historical	Average		x			Partial
	CNP	Minnesota	Gas	1	Fully Forecast	Average		x			Partial
	CNP	Ohio	Gas	1	Partially Forecast	Year End				x	Partial
	CNP	Texas	Electric	1	Historical	Year End				x	
	CNP	Texas	Gas	1	Historical	Year End				x	
CMS Energy Corporation	CMS	Michigan	Electric	1	Fully Forecast	Average					Yes
	CMS	Michigan	Gas	1	Fully Forecast	Average		x		x	Yes
Dominion Energy, Inc.	D	North Carolina	Electric	1	Historical	Year End					Yes
	D	North Carolina	Gas	1	Historical	Year End	x			x	Yes
	D	Ohio	Gas	1	Partially Forecast	Year End				x	Partial
	D	South Carolina	Electric	1	Historical	N/A			x		Yes
	D	South Carolina	Gas	1	Historical	N/A		x			Yes
	D	Utah	Gas	1	Fully Forecast	Average	x			x	No

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COMPARISON OF PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

		[1]			[2]		[3]				[4]
							Decoupling		New Capital		
Proxy Group Company	TICKER	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure	CWIP in Rate Base
	D	Virginia	Electric	1	Historical	Year End			x	x	No
	D	West Virginia	Gas	1	Historical	Average				x	No (large projects may be allowed)
	D	Wyoming	Gas	1	Historical	Year End		x			No
DTE Energy Company	DTE	Michigan	Electric	1	Fully Forecast	Average					Yes
	DTE	Michigan	Gas	1	Fully Forecast	Average		x		x	Yes
Edison International	EIX	California	Electric	1	Fully Forecast	Average	x				No
Entergy Corporation	ETR	Arkansas	Electric	1	Partially Forecast	Average		x	x	x	No
	ETR	Louisiana-NOCC	Electric	1	Fully Forecast	Average		x	x		Partial
	ETR	Louisiana-NOCC	Gas	1	Fully Forecast	Average					Partial
	ETR	Louisiana	Electric	1	Historical	Average		x	x	x	Partial
	ETR	Louisiana	Gas	1	Historical	Average		x		x	Partial
	ETR	Mississippi	Electric	1	Fully Forecast	Average		x			Partial
	ETR	Texas	Electric	1	Historical	Year End				x	No
Evergy, Inc.	EVRG	Kansas	Electric	1	Historical	Year End		x			Partial
	EVRG	Missouri	Electric	1	Partially Forecast	Year End		x		x	No
Eversource Energy	ES	Connecticut	Electric	1		Average	x			x	No
	ES	Massachusetts	Electric	1	Historical	Year End	x			x	No
	ES	New Hampshire	Electric	1	Historical	Year End		x		x	No
FirstEnergy Corp.	FE	Maryland	Electric	1	Historical	Average					Yes
	FE	New Jersey	Electric	1	Fully Forecasted	Year End		x			No
	FE	Ohio	Electric	1	Partially Forecast	Year End		x		x	Partial
	FE	Pennsylvania	Electric	1	Fully Forecasted	Year End				x	No
	FE	West Virginia	Electric	1	Historical	Average					No (large projects may be allowed)
IDACORP	IDA	Idaho	Electric	1	Partially Forecast	Average	x				No
	IDA	Oregon	Electric	1	Fully Forecast	Average					No
NorthWestern Corporation	NWE	Montana	Electric	1	Historical	Average					No
	NWE	Montana	Gas	1	Historical	Average					No
	NWE	Nebraska	Gas								Yes
	NWE	South Dakota	Elec.		Historical	Average					Rider
	NWE	South Dakota	Gas		Historical	Average					Rider
OGE Energy Corporation	OGE	Arkansas	Electric	1	Partially Forecast	Year End		x	x		No
	OGE	Oklahoma	Electric	1	Historical	Year End		x		x	Yes
Otter Tail Corporation	OTTR	Minnesota	Electric	1	Fully Forecast	Average					Partial
	OTTR	North Dakota	Electric	1	Fully Forecast	Average			x	x	Partial
	OTTR	South Dakota	Electric	1	Historical	Average			x	x	Rider
Sempra Energy	SRE	California	Electric	1	Fully Forecast	Average	x				No
	SRE	California	Gas	1	Fully Forecast	Average	x				No
	SRE	Texas	Electric	1	Historical	Year End				x	No

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COMPARISON OF PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

		[1]			[2]		[3]				[4]
							Decoupling		New Capital		
Proxy Group Company	TICKER	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure	CWIP in Rate Base
Portland General Electric Company	POR	Oregon	Electric	1	Fully Forecast	Average		x	x		No
Southern Company	SO	Alabama	Electric	1	Historical				x		Yes
	SO	Georgia	Electric	1	Partially Forecast	Average			x		Limited basis
	SO	Mississippi	Electric	1	Fully Forecast	Year End		x			Partial
WEC Energy Group, Inc.	WEC	Wisconsin	Electric	1	Fully Forecast	NA					Rider
	WEC	Wisconsin	Gas	1	Fully Forecast	NA					Rider
	WEC	Wisconsin	Gas	1	Fully Forecast	NA					Rider
	WEC	Wisconsin	Electric	1	Fully Forecast	NA					Rider
	WEC	Michigan	Electric	1							Yes
Xcel Energy Inc.	XEL	Colorado	Electric	1	Historical	Average			x	x	Partial
	XEL	Colorado	Gas	1	Historical	Average		x		x	Partial
	XEL	Minnesota	Electric	1	Fully Forecast	Average		x			Partial
	XEL	Minnesota	Gas	1	Fully Forecast	Average				x	Partial
	XEL	New Mexico	Electric	1	Historical	Year End					Yes
	XEL	North Dakota	Electric	1	Fully Forecast	Average				x	Partial
	XEL	North Dakota	Gas	1	Fully Forecast	Average					Partial
	XEL	South Dakota	Electric	1	Historical	Average		x	x	x	Rider
	XEL	Texas	Electric	1	Historical	Year End				x	No
	XEL	Wisconsin	Electric	1	Fully Forecast	Average					Rider
	XEL	Wisconsin	Gas	1	Fully Forecast	Average					Rider
Proxy Company Totals					Forecast: 46	Year End: 39	12	37	16	41	64
Total Jurisdictions				98							
Percent of Jurisdictions					Forecast: 47%	Average: 55%	12.2%	37.8%	16.3%	41.8%	65.3%

Notes:
[1] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated June 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[2] Source: "Alternative Regulation for Evolving Utility Challenges," Prepared by Pacific Economics Group Research for Edison Electric Institute, Table 6, November 2015; S&P RRA Research; Company Investor Presentations.
[3] Source: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated June 2022.
[4] Source: S&P Global Market Intelligence, Regulatory Research Associates, Commission Profiles
[5] This exhibit includes the adjustment mechanisms for the electric and gas distribution companies.

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Aug 08 2023

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [1]

Company Name	Ticker	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	Average
Interstate Power and Light Company	LNT	50.59%	50.55%	50.85%	50.36%	50.31%	50.22%	54.02%	53.67%	51.32%
Wisconsin Power and Light Company	LNT	54.12%	55.03%	52.03%	55.68%	54.83%	52.86%	52.76%	55.10%	54.05%
Ameren Illinois Company	AEE	56.61%	55.83%	57.03%	57.15%	56.72%	56.00%	54.98%	54.27%	56.07%
Union Electric Company	AEE	50.27%	52.20%	52.12%	50.53%	52.42%	52.22%	52.28%	50.65%	51.59%
AEP Texas, Inc.	AEP	43.55%	42.07%	41.73%	39.30%	43.28%	42.81%	41.68%	40.97%	41.92%
Appalachian Power Company	AEP	48.37%	47.76%	47.00%	49.31%	48.93%	48.34%	48.01%	47.55%	48.16%
Indiana Michigan Power Company	AEP	47.89%	49.29%	48.97%	48.34%	47.96%	47.38%	47.48%	47.22%	48.06%
Kentucky Power Company	AEP	43.94%	43.82%	43.90%	45.25%	44.89%	44.17%	44.00%	43.40%	44.17%
Kingsport Power Company	AEP	49.57%	53.89%	53.51%	49.46%	49.39%	54.18%	53.66%	53.51%	52.14%
Ohio Power Company	AEP	51.81%	50.79%	50.34%	49.86%	49.35%	48.76%	44.68%	49.10%	49.34%
Public Service Company of Oklahoma	AEP	50.00%	55.70%	55.82%	49.15%	48.66%	54.36%	54.31%	57.53%	53.19%
Southwestern Electric Power Company	AEP	50.65%	52.54%	52.75%	52.10%	51.64%	48.70%	50.55%	48.78%	50.96%
Wheeling Power Company	AEP	49.60%	49.14%	52.37%	51.40%	54.10%	54.01%	54.00%	53.71%	52.29%
Avista Corporation	AVA	48.58%	50.65%	49.56%	49.59%	46.94%	50.35%	49.73%	51.06%	49.56%
Black Hills Power, Inc.	BKH	62.11%	61.83%	61.61%	61.23%	60.74%	60.10%	60.02%	59.06%	60.84%
Cheyenne Light, Fuel and Power Company	BKH	56.18%	55.98%	57.79%	56.81%	56.14%	56.14%	56.23%	55.74%	56.38%
Southern Indiana Gas and Electric Company, Inc.	CNP	53.35%	56.48%	54.48%	57.62%	57.11%	56.38%	55.12%	57.75%	56.04%
CenterPoint Energy Houston Electric, LLC	CNP	44.59%	44.64%	43.92%	45.25%	41.63%	40.71%	38.98%	37.78%	42.19%
Consumers Energy Company	CMS	49.64%	49.87%	50.89%	54.50%	53.85%	52.38%	52.45%	52.52%	52.01%
South Carolina Electric & Gas Co.	D	55.03%	54.80%	54.77%	54.47%	53.95%	53.94%	56.78%	55.27%	54.88%
Virginia Electric and Power Company	D	51.60%	51.62%	51.25%	49.93%	51.70%	52.80%	53.20%	52.30%	51.80%
DTE Electric Company	DTE	47.25%	50.41%	49.50%	47.96%	47.89%	49.83%	49.25%	47.86%	48.74%
Southern California Edison Company	EIX	43.71%	44.82%	45.90%	46.40%	46.90%	48.09%	48.23%	49.89%	46.74%
Entergy Arkansas, Inc.	ETR	45.35%	47.95%	47.85%	47.17%	46.98%	47.84%	47.97%	47.04%	47.27%
Entergy Louisiana, LLC	ETR	51.05%	47.17%	47.04%	48.16%	40.84%	43.08%	45.02%	44.51%	45.86%
Entergy Mississippi, Inc.	ETR	45.52%	46.43%	44.97%	43.91%	45.94%	45.53%	47.53%	46.65%	45.81%
Entergy New Orleans, LLC	ETR	48.30%	47.94%	47.81%	46.83%	46.10%	45.52%	49.94%	50.31%	47.84%
Entergy Texas, Inc.	ETR	50.74%	50.36%	50.98%	53.15%	52.21%	51.71%	51.18%	50.79%	51.39%
Evergy Metro	EVRG	55.06%	52.03%	53.21%	52.62%	51.85%	51.36%	51.20%	49.86%	52.15%
Evergy Kansas South	EVRG	83.79%	83.66%	83.73%	83.34%	83.22%	83.11%	83.27%	82.90%	83.38%
Evergy Missouri West, Inc.	EVRG	54.57%	54.41%	60.84%	59.64%	52.96%	52.01%	50.37%	49.01%	54.23%
Westar Energy (KPL)	EVRG	55.79%	58.03%	58.57%	58.22%	58.81%	58.52%	58.65%	58.47%	58.13%
Connecticut Light and Power Company	ES	57.89%	58.18%	57.82%	57.53%	56.87%	56.07%	55.21%	54.52%	56.76%
NSTAR Electric Company	ES	55.61%	56.32%	51.95%	53.53%	55.68%	55.58%	54.09%	55.06%	54.73%
Public Service Company of New Hampshire	ES	49.83%	53.77%	53.04%	52.53%	49.56%	49.10%	48.91%	48.44%	50.65%
Cleveland Electric Illuminating Company	FE	55.24%	55.10%	54.91%	54.40%	54.10%	51.41%	51.39%	51.48%	53.50%
Jersey Central Power & Light Company	FE	64.99%	64.86%	64.92%	64.70%	64.57%	64.52%	63.90%	63.80%	64.53%
Metropolitan Edison Company	FE	50.09%	51.85%	52.13%	51.78%	52.23%	50.96%	50.98%	50.60%	51.33%
Monongahela Power Company	FE	49.80%	49.23%	49.09%	46.11%	45.76%	45.10%	43.18%	44.28%	46.57%
Ohio Edison Company	FE	57.69%	57.49%	57.54%	68.20%	67.41%	68.75%	68.15%	68.99%	64.28%
Pennsylvania Electric Company	FE	46.84%	50.97%	50.29%	50.11%	49.48%	50.42%	49.19%	51.27%	49.82%
Potomac Edison Company	FE	54.06%	53.39%	53.11%	52.76%	52.31%	51.43%	50.40%	49.98%	52.18%
Toledo Edison Company	FE	56.59%	57.09%	57.07%	56.64%	56.80%	55.02%	54.92%	55.29%	56.18%
West Penn Power Company	FE	48.55%	48.80%	57.04%	56.59%	53.34%	49.39%	48.67%	50.02%	51.55%
Idaho Power Co.	IDA	50.57%	54.37%	54.23%	53.57%	54.49%	55.00%	55.06%	54.41%	53.96%
NorthWestern Corporation	NWE	50.91%	50.34%	49.73%	49.33%	48.44%	47.82%	47.58%	46.39%	48.82%
Oklahoma Gas and Electric Company	OGE	53.22%	55.65%	55.42%	54.13%	53.59%	53.38%	53.16%	53.14%	53.96%
Otter Tail Power Company	OTTR	55.14%	54.90%	54.77%	52.05%	54.96%	54.79%	54.67%	54.39%	54.46%
Portland General Electric Company	POR	47.10%	43.24%	45.61%	45.40%	45.14%	45.09%	44.79%	47.69%	45.51%
Oncor Electric Delivery Company LLC	SRE	55.94%	56.96%	56.67%	59.09%	57.64%	60.50%	59.77%	58.74%	58.16%
San Diego Gas & Electric Co.	SRE	52.10%	53.82%	53.16%	52.67%	52.81%	56.31%	56.56%	57.44%	54.36%
Alabama Power Company	SO	52.85%	52.22%	52.64%	54.46%	54.23%	53.04%	55.13%	53.98%	53.57%
Georgia Power Company	SO	56.45%	56.05%	56.08%	54.93%	56.96%	55.60%	55.87%	54.85%	55.85%
Mississippi Power Company	SO	55.83%	55.67%	56.43%	56.11%	56.06%	55.40%	54.14%	48.99%	54.83%
Wisconsin Public Service Corporation	WEC	56.43%	54.77%	58.71%	58.39%	58.12%	56.24%	58.53%	57.48%	57.33%
Wisconsin Electric Power Company	WEC	58.71%	56.06%	56.27%	59.71%	60.59%	58.78%	59.23%	57.93%	58.41%
Northern States Power Company - MN	XEL	53.15%	52.79%	52.14%	51.86%	52.52%	52.65%	52.62%	52.07%	52.48%
Northern States Power Company - WI	XEL	54.42%	53.45%	53.29%	54.30%	53.76%	52.53%	52.07%	54.87%	53.59%
Public Service Company of Colorado	XEL	58.33%	57.18%	56.56%	55.69%	56.81%	56.44%	56.05%	55.42%	56.56%
Southwestern Public Service Company	XEL	54.22%	54.30%	54.21%	54.28%	54.28%	54.23%	54.25%	54.19%	54.25%
MEAN		52.70%	53.11%	53.30%	53.26%	52.95%	52.82%	52.77%	52.66%	52.94%

Notes:
[1] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis. Analysis excludes natural gas subsidiaries. Ohio Edison Company subsidiary, Pennsylvania Power Company, excluded, as Ohio Power Company included in analysis. Black Hills Colorado Electric Utility Company, LP, is co-owned by Black Hills, and is excluded from the analysis. Alaska Electric Light and Power Company excluded, as Avista Corporation reported on a consolidated basis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	Average
Interstate Power and Light Company	LNT	49.41%	49.45%	49.15%	49.64%	49.69%	49.78%	45.98%	46.33%	48.68%
Wisconsin Power and Light Company	LNT	45.88%	44.97%	47.97%	44.32%	45.17%	47.14%	47.24%	44.90%	45.95%
Ameren Illinois Company	AEE	43.39%	44.17%	42.97%	42.85%	43.28%	44.00%	45.02%	45.73%	43.93%
Union Electric Company	AEE	49.73%	47.80%	47.88%	49.47%	47.58%	47.78%	47.72%	49.35%	48.41%
AEP Texas, Inc.	AEP	56.45%	57.93%	58.27%	60.70%	56.72%	57.19%	58.32%	59.03%	58.08%
Appalachian Power Company	AEP	51.63%	52.24%	53.00%	50.69%	51.07%	51.66%	51.99%	52.45%	51.84%
Indiana Michigan Power Company	AEP	52.11%	50.71%	51.03%	51.66%	52.04%	52.62%	52.52%	52.78%	51.94%
Kentucky Power Company	AEP	56.06%	56.18%	56.10%	54.75%	55.11%	55.83%	56.00%	56.60%	55.83%
Kingsport Power Company	AEP	50.43%	46.11%	46.49%	50.54%	50.61%	45.82%	46.34%	46.49%	47.86%
Ohio Power Company	AEP	48.19%	49.21%	49.66%	50.14%	50.65%	51.24%	55.32%	50.90%	50.66%
Public Service Company of Oklahoma	AEP	50.00%	44.30%	44.18%	50.85%	51.34%	45.64%	45.69%	42.47%	46.81%
Southwestern Electric Power Company	AEP	49.35%	47.46%	47.25%	47.90%	48.36%	51.30%	49.45%	51.22%	49.04%
Wheeling Power Company	AEP	50.40%	50.86%	47.63%	48.60%	45.90%	45.99%	46.00%	46.29%	47.71%
Avista Corporation	AVA	51.42%	49.35%	50.44%	50.41%	53.06%	49.65%	50.27%	48.94%	50.44%
Black Hills Power, Inc.	BKH	37.89%	38.17%	38.39%	38.77%	39.26%	39.90%	39.98%	40.94%	39.16%
Cheyenne Light, Fuel and Power Company	BKH	43.82%	44.02%	42.21%	43.19%	43.86%	43.86%	43.77%	44.26%	43.62%
Southern Indiana Gas and Electric Company, Inc.	CNP	46.65%	43.52%	45.52%	42.38%	42.89%	43.62%	44.88%	42.25%	43.96%
CenterPoint Energy Houston Electric, LLC	CNP	55.41%	55.36%	56.08%	54.75%	58.37%	59.29%	61.02%	62.22%	57.81%
Consumers Energy Company	CMS	50.36%	50.13%	49.11%	45.50%	46.15%	47.62%	47.55%	47.48%	47.99%
South Carolina Electric & Gas Co.	D	44.97%	45.20%	45.23%	45.53%	46.05%	46.06%	43.22%	44.73%	45.12%
Virginia Electric and Power Company	D	48.40%	48.38%	48.75%	50.07%	48.30%	47.20%	46.80%	47.70%	48.20%
DTE Electric Company	DTE	52.75%	49.59%	50.50%	52.04%	52.11%	50.17%	50.75%	52.14%	51.26%
Southern California Edison Company	EIX	56.29%	55.18%	54.10%	53.60%	53.10%	51.91%	51.77%	50.11%	53.26%
Entergy Arkansas, Inc.	ETR	54.65%	52.05%	52.15%	52.83%	53.02%	52.16%	52.03%	52.96%	52.73%
Entergy Louisiana, LLC	ETR	48.95%	52.83%	52.96%	51.84%	59.16%	56.92%	54.98%	55.49%	54.14%
Entergy Mississippi, Inc.	ETR	54.48%	53.57%	55.03%	56.09%	54.06%	54.47%	52.47%	53.35%	54.19%
Entergy New Orleans, LLC	ETR	51.70%	52.06%	52.19%	53.17%	53.90%	54.48%	50.06%	49.69%	52.16%
Entergy Texas, Inc.	ETR	49.26%	49.64%	49.02%	46.85%	47.79%	48.29%	48.82%	49.21%	48.61%
Evergy Metro	EVRG	44.94%	47.97%	46.79%	47.38%	48.15%	48.64%	48.80%	50.14%	47.85%
Evergy Kansas South	EVRG	16.21%	16.34%	16.27%	16.66%	16.78%	16.89%	16.73%	17.10%	16.62%
Evergy Missouri West, Inc.	EVRG	45.43%	45.59%	39.16%	40.36%	47.04%	47.99%	49.63%	50.99%	45.77%
Westar Energy (KPL)	EVRG	44.21%	41.97%	41.43%	41.78%	41.19%	41.48%	41.35%	41.53%	41.87%
Connecticut Light and Power Company	ES	42.11%	41.82%	42.18%	42.47%	43.13%	43.93%	44.79%	45.48%	43.24%
NSTAR Electric Company	ES	44.39%	43.68%	48.05%	46.47%	44.32%	44.42%	45.91%	44.94%	45.27%
Public Service Company of New Hampshire	ES	50.17%	46.23%	46.96%	47.47%	50.44%	50.90%	51.09%	51.56%	49.35%
Cleveland Electric Illuminating Company	FE	44.76%	44.90%	45.09%	45.60%	45.90%	48.59%	48.61%	48.52%	46.50%
Jersey Central Power & Light Company	FE	35.01%	35.14%	35.08%	35.30%	35.43%	35.48%	36.10%	36.20%	35.47%
Metropolitan Edison Company	FE	49.91%	48.15%	47.87%	48.22%	47.77%	49.04%	49.02%	49.40%	48.67%
Monongahela Power Company	FE	50.20%	50.77%	50.91%	53.89%	54.24%	54.90%	56.82%	55.72%	53.43%
Ohio Edison Company	FE	42.31%	42.51%	42.46%	31.80%	32.59%	31.25%	31.85%	31.01%	35.72%
Pennsylvania Electric Company	FE	53.16%	49.03%	49.71%	49.89%	50.52%	49.58%	50.81%	48.73%	50.18%
Potomac Edison Company	FE	45.94%	46.61%	46.89%	47.24%	47.69%	48.57%	49.60%	50.02%	47.82%
Toledo Edison Company	FE	43.41%	42.91%	42.93%	43.36%	43.20%	44.98%	45.08%	44.71%	43.82%
West Penn Power Company	FE	51.45%	51.20%	42.96%	43.41%	46.66%	50.61%	51.33%	49.98%	48.45%
Idaho Power Co.	IDA	49.43%	45.63%	45.77%	46.43%	45.51%	45.00%	44.94%	45.59%	46.04%
NorthWestern Corporation	NWE	49.09%	49.66%	50.27%	50.67%	51.56%	52.18%	52.42%	53.61%	51.18%
Oklahoma Gas and Electric Company	OGE	46.78%	44.35%	44.58%	45.87%	46.41%	46.62%	46.84%	46.86%	46.04%
Otter Tail Power Company	OTTR	44.86%	45.10%	45.23%	47.95%	45.04%	45.21%	45.33%	45.61%	45.54%
Portland General Electric Company	POR	52.90%	56.76%	54.39%	54.60%	54.86%	54.91%	55.21%	52.31%	54.49%
Oncor Electric Delivery Company LLC	SRE	44.06%	43.04%	43.33%	40.91%	42.36%	39.50%	40.23%	41.26%	41.84%
San Diego Gas & Electric Co.	SRE	47.90%	46.18%	46.84%	47.33%	47.19%	43.69%	43.44%	42.56%	45.64%
Alabama Power Company	SO	47.15%	47.78%	47.36%	45.54%	45.77%	46.96%	44.87%	46.02%	46.43%
Georgia Power Company	SO	43.55%	43.95%	43.92%	45.07%	43.04%	44.40%	44.13%	45.15%	44.15%
Mississippi Power Company	SO	44.17%	44.33%	43.57%	43.89%	43.94%	44.60%	45.86%	51.01%	45.17%
Wisconsin Public Service Corporation	WEC	43.57%	45.23%	41.29%	41.61%	41.88%	43.76%	41.47%	42.52%	42.67%
Wisconsin Electric Power Company	WEC	41.29%	43.94%	43.73%	40.29%	39.41%	41.22%	40.77%	42.07%	41.59%
Northern States Power Company - MN	XEL	46.85%	47.21%	47.86%	48.14%	47.48%	47.35%	47.38%	47.93%	47.52%
Northern States Power Company - WI	XEL	45.58%	46.55%	46.71%	45.70%	46.24%	47.47%	47.93%	45.13%	46.41%
Public Service Company of Colorado	XEL	41.67%	42.82%	43.44%	44.31%	43.19%	43.56%	43.95%	44.58%	43.44%
Southwestern Public Service Company	XEL	45.78%	45.70%	45.79%	45.72%	45.72%	45.77%	45.75%	45.81%	45.75%
MEAN		47.30%	46.89%	46.70%	46.74%	47.05%	47.18%	47.23%	47.34%	47.06%

Notes:
[1] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis. Analysis excludes natural gas subsidiaries. Ohio Edison Company subsidiary, Pennsylvania Power Company, excluded, as Ohio Power Company included in analysis. Black Hills Colorado Electric Utility Company, LP, is co-owned by Black Hills, and is excluded from the analysis. Alaska Electric Light and Power Company excluded, as Avista Corporation reported on a consolidated basis.

I/A

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [1]

Company Name	Ticker	2023Q1	2022Q4	2022Q3	2022Q2	2022Q1	2021Q4	2021Q3	2021Q2	Average	*Adjusted**
Interstate Power and Light Company	LNT	50.59%	50.55%	50.85%	50.36%	50.31%	50.22%	54.02%	53.67%	51.32%	*51.32%*
Wisconsin Power and Light Company	LNT	54.12%	55.03%	52.03%	55.68%	54.83%	52.86%	52.76%	55.10%	54.05%	*54.05%*
Ameren Illinois Company	AEE	56.61%	55.83%	57.03%	57.15%	56.72%	56.00%	54.98%	54.27%	56.07%	*56.07%*
Union Electric Company	AEE	50.27%	52.20%	52.12%	50.53%	52.42%	52.22%	52.28%	50.65%	51.59%	*51.59%*
AEP Texas, Inc.	AEP	43.55%	42.07%	41.73%	39.30%	43.28%	42.81%	41.68%	40.97%	41.92%	*41.92%*
Appalachian Power Company	AEP	48.37%	47.76%	47.00%	49.31%	48.93%	48.34%	48.01%	47.55%	48.16%	*48.16%*
Indiana Michigan Power Company	AEP	47.89%	49.29%	48.97%	48.34%	47.96%	47.38%	47.48%	47.22%	48.06%	*48.06%*
Kentucky Power Company	AEP	43.94%	43.82%	43.90%	45.25%	44.89%	44.17%	44.00%	43.40%	44.17%	*44.17%*
Kingsport Power Company	AEP	49.57%	53.89%	53.51%	49.46%	49.39%	54.18%	53.66%	53.51%	52.14%	*52.14%*
Ohio Power Company	AEP	51.81%	50.79%	50.34%	49.86%	49.35%	48.76%	44.68%	49.10%	49.34%	*49.34%*
Public Service Company of Oklahoma	AEP	50.00%	55.70%	55.82%	49.15%	48.66%	54.36%	54.31%	57.53%	53.19%	*53.19%*
Southwestern Electric Power Company	AEP	50.65%	52.54%	52.75%	52.10%	51.64%	48.70%	50.55%	48.78%	50.96%	*50.96%*
Wheeling Power Company	AEP	49.60%	49.14%	52.37%	51.40%	54.10%	54.01%	54.00%	53.71%	52.29%	*52.29%*
Avista Corporation	AVA	48.58%	50.65%	49.56%	49.59%	46.94%	50.35%	49.73%	51.06%	49.56%	*49.56%*
Black Hills Power, Inc.	BKH	62.11%	61.83%	61.61%	61.23%	60.74%	60.10%	60.02%	59.06%	60.84%	*53.32%*
Cheyenne Light, Fuel and Power Company	BKH	56.18%	55.98%	57.79%	56.81%	56.14%	56.14%	56.23%	55.74%	56.38%	*56.38%*
Southern Indiana Gas and Electric Company, Inc.	CNP	53.35%	56.48%	54.48%	57.62%	57.11%	56.38%	55.12%	57.75%	56.04%	*56.04%*
CenterPoint Energy Houston Electric, LLC	CNP	44.59%	44.64%	43.92%	45.25%	41.63%	40.71%	38.98%	37.78%	42.19%	*42.19%*
Consumers Energy Company	CMS	49.64%	49.87%	50.89%	54.50%	53.85%	52.38%	52.45%	52.52%	52.01%	*52.01%*
South Carolina Electric & Gas Co.	D	55.03%	54.80%	54.77%	54.47%	53.95%	53.94%	56.78%	55.27%	54.88%	*54.88%*
Virginia Electric and Power Company	D	51.60%	51.62%	51.25%	49.93%	51.70%	52.80%	53.20%	52.30%	51.80%	*51.80%*
DTE Electric Company	DTE	47.25%	50.41%	49.50%	47.96%	47.89%	49.83%	49.25%	47.86%	48.74%	*48.74%*
Southern California Edison Company	EIX	43.71%	44.82%	45.90%	46.40%	46.90%	48.09%	48.23%	49.89%	46.74%	*46.74%*
Entergy Arkansas, Inc.	ETR	45.35%	47.95%	47.85%	47.17%	46.98%	47.84%	47.97%	47.04%	47.27%	*47.27%*
Entergy Louisiana, LLC	ETR	51.05%	47.17%	47.04%	48.16%	40.84%	43.08%	45.02%	44.51%	45.86%	*45.86%*
Entergy Mississippi, Inc.	ETR	45.52%	46.43%	44.97%	43.91%	45.94%	45.53%	47.53%	46.65%	45.81%	*45.81%*
Entergy New Orleans, LLC	ETR	48.30%	47.94%	47.81%	46.83%	46.10%	45.52%	49.94%	50.31%	47.84%	*47.84%*
Entergy Texas, Inc.	ETR	50.74%	50.36%	50.98%	53.15%	52.21%	51.71%	51.18%	50.79%	51.39%	*51.39%*
Evergy Metro	EVRG	55.06%	52.03%	53.21%	52.62%	51.85%	51.36%	51.20%	49.86%	52.15%	*52.15%*
Evergy Kansas South	EVRG	83.79%	83.66%	83.73%	83.34%	83.22%	83.11%	83.27%	82.90%	83.38%	*52.0376%*
Evergy Missouri West, Inc.	EVRG	54.57%	54.41%	60.84%	59.64%	52.96%	52.01%	50.37%	49.01%	54.23%	*54.23%*
Westar Energy (KPL)	EVRG	55.79%	58.03%	58.57%	58.22%	58.81%	58.52%	58.65%	58.47%	58.13%	*58.13%*
Connecticut Light and Power Company	ES	57.89%	58.18%	57.82%	57.53%	56.87%	56.07%	55.21%	54.52%	56.76%	*56.76%*
NSTAR Electric Company	ES	55.61%	56.32%	51.95%	53.53%	55.68%	55.58%	54.09%	55.06%	54.73%	*54.73%*

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Public Service Company of New Hampshire	ES	49.83%	53.77%	53.04%	52.53%	49.56%	49.10%	48.91%	48.44%	50.65%	*50.65%*
Cleveland Electric Illuminating Company	FE	55.24%	55.10%	54.91%	54.40%	54.10%	51.41%	51.39%	51.48%	53.50%	*53.50%*
Jersey Central Power & Light Company	FE	64.99%	64.86%	64.92%	64.70%	64.57%	64.52%	63.90%	63.80%	64.53%	*51.44%*
Metropolitan Edison Company	FE	50.09%	51.85%	52.13%	51.78%	52.23%	50.96%	50.98%	50.60%	51.33%	*51.33%*
Monongahela Power Company	FE	49.80%	49.23%	49.09%	46.11%	45.76%	45.10%	43.18%	44.28%	46.57%	*46.57%*
Ohio Edison Company	FE	57.69%	57.49%	57.54%	68.20%	67.41%	68.75%	68.15%	68.99%	64.28%	*50.10%*
Pennsylvania Electric Company	FE	46.84%	50.97%	50.29%	50.11%	49.48%	50.42%	49.19%	51.27%	49.82%	*49.82%*
Potomac Edison Company	FE	54.06%	53.39%	53.11%	52.76%	52.31%	51.43%	50.40%	49.98%	52.18%	*52.18%*
Toledo Edison Company	FE	56.59%	57.09%	57.07%	56.64%	56.80%	55.02%	54.92%	55.29%	56.18%	*56.18%*
West Penn Power Company	FE	48.55%	48.80%	57.04%	56.59%	53.34%	49.39%	48.67%	50.02%	51.55%	*51.55%*
Idaho Power Co.	IDA	50.57%	54.37%	54.23%	53.57%	54.49%	55.00%	55.06%	54.41%	53.96%	*53.96%*
NorthWestern Corporation	NWE	50.91%	50.34%	49.73%	49.33%	48.44%	47.82%	47.58%	46.39%	48.82%	*48.82%*
Oklahoma Gas and Electric Company	OGE	53.22%	55.65%	55.42%	54.13%	53.59%	53.38%	53.16%	53.14%	53.96%	*53.96%*
Otter Tail Power Company	OTTR	55.14%	54.90%	54.77%	52.05%	54.96%	54.79%	54.67%	54.39%	54.46%	*54.46%*
Portland General Electric Company	POR	47.10%	43.24%	45.61%	45.40%	45.14%	45.09%	44.79%	47.69%	45.51%	*45.51%*
Oncor Electric Delivery Company LLC	SRE	55.94%	56.96%	56.67%	59.09%	57.64%	60.50%	59.77%	58.74%	58.16%	*58.16%*
San Diego Gas & Electric Co.	SRE	52.10%	53.82%	53.16%	52.67%	52.81%	56.31%	56.56%	57.44%	54.36%	*54.36%*
Alabama Power Company	SO	52.85%	52.22%	52.64%	54.46%	54.23%	53.04%	55.13%	53.98%	53.57%	*53.57%*
Georgia Power Company	SO	56.45%	56.05%	56.08%	54.93%	56.96%	55.60%	55.87%	54.85%	55.85%	*55.85%*
Mississippi Power Company	SO	55.83%	55.67%	56.43%	56.11%	56.06%	55.40%	54.14%	48.99%	54.83%	*54.83%*
Wisconsin Public Service Corporation	WEC	56.43%	54.77%	58.71%	58.39%	58.12%	56.24%	58.53%	57.48%	57.33%	*57.33%*
Wisconsin Electric Power Company	WEC	58.71%	56.06%	56.27%	59.71%	60.59%	58.78%	59.23%	57.93%	58.41%	*58.41%*
Northern States Power Company - MN	XEL	53.15%	52.79%	52.14%	51.86%	52.52%	52.65%	52.62%	52.07%	52.48%	*52.48%*
Northern States Power Company - WI	XEL	54.42%	53.45%	53.29%	54.30%	53.76%	52.53%	52.07%	54.87%	53.59%	*53.59%*
Public Service Company of Colorado	XEL	58.33%	57.18%	56.56%	55.69%	56.81%	56.44%	56.05%	55.42%	56.56%	*56.56%*
Southwestern Public Service Company	XEL	54.22%	54.30%	54.21%	54.28%	54.28%	54.23%	54.25%	54.19%	54.25%	*54.25%*
MEAN		52.70%	53.11%	53.30%	53.26%	52.95%	52.82%	52.77%	52.66%	52.94%	*51.84%*

Notes:

[1] Natural Gas and Electric Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis. Analysis excludes natural gas subsidiaries. Ohio Edison Company subsidiary, Pennsylvania Power Company, excluded, as Ohio Power Company included in analysis. Black Hills Colorado Electric Utility Company, LP, is co-owned by Black Hills, and is excluded from the analysis. Alaska Electric Light and Power Company excluded, as Avista Corporation reported on a consolidated basis.

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S&P Capital IQ PRO

Ohio Edison Company: OH: C-07-0551-EL-AIR (OE) | Rate Case Profile

State Name	Ohio
Commission Ranking	Average / 2
Company	Ohio Edison Company
Action or Status	Permanent rate increase authorized
Docket	C-07-0551-EL-AIR (OE)

Case History

EVENT DATE	ACTION OR STATUS	RATE CHANGE
6/7/2007	Electric distr bution rate increase requested	$160.8E
12/4/2007	Rate increase recommended by staff (equal to midpoint of $56.9-65.6 million range)	$61.3E
2/11/2008	Staff recommendation revised (mid-point of $56.2-64.7 million)	$70.1E
1/21/2009	Permanent rate increase authorized	$68.9E

Rate Case Summary

	PRESENT CASE: REQUESTED BY COMPANY 6/7/2007	PRESENT CASE: AUTHORIZED BY COMMISSION 1/21/2009	PREVIOUS CASE: AUTHORIZED BY COMMISSION 8/16/1990
Rate Change Amount ($)	160,762,886	68,918,262	142,400,000
Rate Change/ Revenue (%)	31.05	13.56	8.50
Rate Case Test Year End Date	2/29/2008	2/29/2008	12/31/1989
Rate Base ($)	1,590,780,196	1,251,251,538	4,045,600,000
Rate Base Valuation Method	Date Certain	Date Certain	Date Certain
Return on Equity (%)	11.75	10.50	13.21
Common Equity to Total Capital (%)	49.00	49.00	43.53
Rate of Return (%)	9.06	8.48	11.20

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Pennsylvania Power Company: PA: D-R-2016-2537355 | Rate Case Profile

State Name	Pennsylvania
Commission Ranking	Average / 2
Company	Pennsylvania Power Company
Action or Status	Final compliance tariffs filed
Docket	D-R-2016-2537355

Case History

EVENT DATE	ACTION OR STATUS	RATE CHANGE
4/28/2016	Electric rate increase requested	$42.0E
10/17/2016	Settlement filed, rate increase specified	$27.5E
11/21/2016	ALJ recommends adoption of settlement/rate increase	$27.5E
1/19/2017	Settlement adopted, rate increase authorized	$27.5E
1/27/2017	New rates effective	$27.5E
2/3/2017	Petition for reconsideration filed	$
2/9/2017	Petition for reconsideration granted	$
3/23/2017	Final compliance tariffs filed	$27.5E

Rate Case Summary

	PRESENT CASE: REQUESTED BY COMPANY 4/28/2016	PRESENT CASE: AUTHORIZED BY COMMISSION 1/19/2017	PREVIOUS CASE: AUTHORIZED BY COMMISSION 4/9/2015
Rate Change Amount ($)	42,033,000	27,500,000	25,459,309
Rate Change/ Revenue (%)	9.57	6.64	7.79
Rate Case Test Year End Date	12/31/2017	12/31/2017	4/30/2016
Rate Base ($)	413,519,000	NA	NA
Rate Base Valuation Method	Year-end	NA	NA
Return on Equity (%)	11.50	NA	NA
Common Equity to Total Capital (%)	50.10	NA	NA
Rate of Return (%)	8.70	NA	NA

Footnotes

Requested increase includes the roll in to base rates of $4.6 million being collected through the distribution system improvement charge. Hence the net impact on ratepayers would be a $37.4 million rate increase.

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S&P Capital IQ PRO

Pennsylvania Power Company: PA: D-R-2016-2537355 | Rate Case Profile

Settlement and PUC order call for an incremental $1.7 million to be collected through certain surcharges.

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EXHIBIT JC-6

BEFORE THE

NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Bill Wang

Re: Capital Structure and Cost of Capital

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EXHIBIT JC-6

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Bill Wang. My business address is 76 South Main Street, Akron, OH 44308.

Q. **By whom are you employed and in what capacity?**

A. I am employed by FirstEnergy Service Company ("FESC"). My title is Assistant Treasurer. I am also the Treasurer for Jersey Central Power & Light Company ("JCP&L" or the "Company").

Q. **What are your current responsibilities?**

A. I am responsible for managing the FirstEnergy Corp. ("FirstEnergy") family's pension and other post-retirement plan investments and supporting finance-related activities including budgeting, forecasting, and financial planning. I have served as the Treasurer of JCP&L since 2012. As Treasurer of JCP&L, I am responsible for treasury activities including capital markets, liquidity management, derivatives, investment management, and debt compliance.

Q. **Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?**

A. I have not filed written testimony with the BPU. However, I have appeared before the BPU at a public hearing in BPU Docket No. EF20110702.

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EXHIBIT JC-6

Q. Please describe your educational background and professional experience.

A. I joined Corning Incorporated ("Corning") as a Senior Financial Analyst in May 2001 after I received my MBA from the Business School of University of Maryland in College Park. At Corning, I was part of the Treasury team, and participated in its capital structure management including various capital market transactions and banking relationship management. In July 2005, I joined Allegheny Energy, Inc. which was purchased by FirstEnergy in 2011. I was elected to Assistant Treasurer in 2016. Prior to that, I served in various Treasury positions such as Director, Treasury Integration and Director, Investment Management, managing the company's capital structure, asset investments related to the company's pension, savings and other post-retirement plans.

Q. What is the purpose of your direct testimony?

A. My testimony will describe and explain: (1) JCP&L's capital structure; (2) JCP&L's embedded cost of long-term debt; (3) JCP&L's overall weighted average cost of capital; and (4) the impact of timely recovery on JCP&L's credit metrics.

Q. Please identify and describe the schedules to your testimony.

A. I have attached to my testimony five Schedules, identified as follows:

Schedule BW-1 Capital Structures of FirstEnergy Corp. and JCP&L
Schedule BW-2 Recommended Capital Structure for JCP&L
Schedule BW-3 Embedded Cost of JCP&L's Long-Term Debt
Schedule BW-4 JCP&L's Weighted Average Cost of Capital
Schedule BW-5 Standard & Poor's October 19, 2021 Research Update

II. CAPITAL STRUCTURE

Q. Why have you presented the capital structures both for JCP&L and FirstEnergy?

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EXHIBIT JC-6

A. I have included the capital structures for both FirstEnergy and JCP&L in Schedule BW-1 because it is a requirement contained in the Stipulation entered into by several parties including JCP&L, the Division of the Ratepayer Advocate (now the Division of Rate Counsel) and Board Staff in connection with the merger between FirstEnergy and JCP&L's former parent company, GPU, Inc., which was approved in the Board's Order dated October 9, 2001 in Docket No. EM00110870. The relevant provision of the Stipulation states as follows:

> JCP&L further agrees to file, in all future base rate cases, its case using two alternative capital structures. One of the alternatives will be a consolidated capital structure based on the capital structure that is maintained by FirstEnergy (the holding company). The second alternative will be a stand-alone JCP&L capital structure. The parties to future base rate cases will be free to argue for the benefits of using either capital structure for ratemaking purposes or another alternative.

I recommend, however, that JCP&L's capital structure be used in this case, rather than that of FirstEnergy.

Q. Why should JCP&L's capital structure be used in this case?

A. The purpose of this rate proceeding is to determine the appropriate rates for the regulated entity, JCP&L. Those rates should be based on JCP&L's rate base, revenues, and expenses, and should provide a fair rate of return that reflects the risk-return profile of JCP&L, and not FirstEnergy. FirstEnergy is a non-regulated entity, and its assets and liabilities, revenues and expenses are not being evaluated in this proceeding, nor is there any assessment in this proceeding of FirstEnergy's unique risk-return profile, which is separate and distinct from that of JCP&L. In addition, it is my understanding that the Board's long-standing practice is to use the utility's own capital structure for ratemaking purposes.

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EXHIBIT JC-6

Q. Please describe what the projected actual capital structure of JCP&L will be on September 30, 2023.

A. JCP&L's projected capital structure of 34.2% debt and 65.8% equity on September 30, 2023 is shown in Schedule BW-1. This calculation includes JCP&L's goodwill balance. Total debt for purposes of the capital structure to be utilized in this proceeding does not include the balances of short-term debt. Short-term borrowings are sources of liquidity and are not utilized to finance long-lived assets, such as those included in JCP&L's rate base. Furthermore, it is the Board's practice to exclude short-term debt from a utility's capital structure in the context of base rate cases.

Q. Why are you proposing a capital structure at September 30, 2023, rather than at the end of the test year?

A. The Board's long-standing practice regarding post-test year adjustments to capital structure is based on its decision in *In re Elizabethtown Water Company*, Dkt. No WR8504330 (Order dated May 23, 1985), at 2 ("*Elizabethtown Water*"). According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecast data, utilities are generally permitted to include in base rate requests known and measurable adjustments to the capital structure three months beyond the test year for rate base. In the application of *Elizabethtown Water* in this case, the capital structure at September 30, 2023 only differs from the end of the test year, at June 30, 2023, by the forecasted retained earnings.

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EXHIBIT JC-6

Q. Are you proposing an adjusted JCP&L capital structure?

A. Yes. JCP&L recognizes that its projected capital structure at September 30, 2023 has an equity percentage that is outside the range typically approved for ratemaking purposes in New Jersey. JCP&L is proposing to lower its equity percentage by subtracting out its goodwill balance. This adjustment was utilized in the capital structure calculation in JCP&L's 2020 base rate case.[1] Therefore, JCP&L is proposing an adjusted hypothetical capital structure of 48.1% debt and 51.9% equity, as reflected in Schedule BW-2, instead of its actual capital structure.

Q. Are there any other comments you would like to make with regard to capital structure?

A. Yes. I believe that it is vital that JCP&L maintains access to the capital markets on favorable terms. Setting a rate of return which is based on a capital structure that warrants solid investment grade ratings is necessary because it allows JCP&L to access the capital markets on favorable terms, to maintain its financial integrity and financial flexibility, and fund investments in its distribution system that are necessary for safe, proper and adequate service. Customers, in turn, benefit from JCP&L incurring lower debt costs as a result.

[1] The Stipulation of Settlement, dated October 15, 2020, was approved by the New Jersey Board of Public Utilities on October 28, 2020 (BPU Docket No. ER20020146, OAL Docket No. PUC 04343-2020N). Paragraph 10: *The Parties further agree that the revenue increase is based on a post-tax rate of return of 7.40%, with a capital structure consisting of 51.44% common equity with a cost rate of 9.60%, and 48.56% long term debt with a cost rate of 5.083%.*

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EXHIBIT JC-6

III. COST OF CAPITAL

Q. Please describe the calculation of JCP&L's overall embedded cost of long-term debt.

A. Schedule BW-3 contains the embedded cost schedules for JCP&L's long-term debt. The long-term debt schedule details each series of debt, the date of issuance, maturity, original amount issued and current amount outstanding. The issuance expenses (column 4) represent legal, underwriting, and other miscellaneous costs associated with the issuance. The original amount issued plus any premium or minus any discount, reduced by any issuance expenses, results in the net proceeds. The embedded cost rate (column 7) is calculated by taking the net proceeds at the time of issuance and calculating the internal rate of return based on the coupon and the years to maturity. After the embedded rate is calculated for each individual series, the rates are weighted by taking the embedded rate multiplied by the adjusted amount outstanding (amount outstanding multiplied by the net proceeds ratio) and divided by the total adjusted amount of long-term debt outstanding. The embedded cost (column 8) is the embedded rate multiplied by the adjusted amount outstanding, which is calculated by multiplying the net proceeds ratio by the current amount outstanding. As shown on Schedule BW-3, these calculations produce an overall embedded long-term debt cost rate of 4.572%.

Q. How does the current long-term debt cost rate of 4.572% compare to the long-term debt cost rate approved in the Company's last rate case?

A. The long-term debt cost rate approved by the Board in JCP&L's last base rate case and currently reflected in base rates is 5.083%. The effect of the $500 million

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issuance in June 2021 resulted in a decrease of 51.1 basis points in the long-term debt cost rate.

Q. Please describe the calculation of the weighted average cost of capital.

A. I have calculated JCP&L's weighted average cost of capital to be 7.60%. The calculation of the weighted average cost of capital is shown on Schedule BW-4. The calculation weights the cost of common equity and embedded cost of long-term debt by the adjusted ratemaking capitalization ratios. The cost of common equity is supported by the testimony of Dylan D'Ascendis in this filing (Exhibit JC-7). The adjusted ratemaking capitalization ratios are sourced from Schedule BW-2 and have been described earlier in my testimony. The embedded cost of long-term debt is sourced from Schedule BW-3 and has been described earlier in my testimony.

IV. NEAR-TERM IMPACTS OF CASH REQUIREMENTS ON JCP&L CREDIT RATINGS

Q. Why is it important for an electric utility to have strong credit ratings?

A. The electric utility industry is engaged in the development of electric infrastructure, which makes it a highly capital-intensive industry. To fund investments in electric infrastructure, electric utilities must be able to effectively and efficiently access the capital markets to ensure adequate liquidity to support construction, maintenance and operation of the transmission and distribution systems. A utility's credit ratings impact the cost to the utility to raise capital. As the cost of capital is a component of the utility's cost of service and is recovered through electric service charges, the utility's credit ratings ultimately affect costs paid by customers for electric service.

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EXHIBIT JC-6

Q. What are the current credit ratings for FirstEnergy and JCP&L from the three nationally recognized statistical ratings organizations ("NRSRO")?

A. The current credit ratings from Standard & Poor's ("S&P"), Moody's Investor Service ("Moody's") and Fitch Ratings ("Fitch"), as of March 15, 2023, are listed in the table below.

	Issuer/Corporate Family			Senior Unsecured Debt		
	S&P	Moody's	Fitch	S&P	Moody's	Fitch
FirstEnergy	BBB-	Ba1	BBB-	BB+	Ba1	BBB-
JCP&L	BBB	A3	BBB	BBB	A3	BBB+

Q. Do credit ratings of the parent company such as FirstEnergy affect the ratings of the subsidiaries in a corporate group or holding company?

A. Yes. Rating agencies consider the linkages between parent companies and subsidiaries when establishing credit ratings. The manner and extent to which these linkages are considered for ratings purposes are different for each rating agency, based on each agency's respective ratings methodology. As a result, the credit profile of the parent and subsidiaries within the corporate group or holding company may affect the credit ratings of a subsidiary, based on, and including but not limited to, the business risk and financial risk of the business activities of the parent and other subsidiaries, and the extent to which the parent and subsidiaries are financially interdependent.

However, corporate groups and holding companies can take measures to insulate a subsidiary from other subsidiaries and the parent for the purpose of protecting a subsidiary from the consequences of financial events (e.g., bankruptcy)

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at the parent or other subsidiaries within the corporate group or holding company. Such measures or practices are referred to as "ring-fencing." Effective ring-fencing may enable higher credit ratings for a subsidiary within a comparably weaker corporate group or holding company. This is the case for JCP&L, as ring-fencing measures in place enable JCP&L to have higher credit ratings than its parent from all three major ratings agencies. In fact, JCP&L's Issuer and Senior Unsecured credit ratings are four notches higher than FirstEnergy at Moody's, and JCP&L's Senior Unsecured Debt is rated two notches higher by S&P and Fitch.

Q. What are some of the actions taken following the downgrades of FirstEnergy and its subsidiaries by S&P and Fitch in the fall of 2020 to support improvement of those ratings?

A. Regarding JCP&L, in October 2021, FirstEnergy established six individual revolving credit facilities, including one which is JCP&L-specific. FirstEnergy previously had in place two separate revolving credit facilities providing for aggregate commitments of $3.5 billion, a $2.5 billion commitment for FirstEnergy and its regulated subsidiaries (including JCP&L) and a $1 billion commitment for FirstEnergy's transmission subsidiaries. Each revolving credit facility had individual sub-limits for each participant. JCP&L now has its own revolving credit facility, with a commitment of $500 million that is equal to its Federal Energy Regulatory Commission authorized short-term borrowing authority. The purpose of this step was to provide for further ring-fencing for JCP&L by diminishing the financial linkages between JCP&L, its parent, and FirstEnergy's other subsidiaries.

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Meanwhile, FirstEnergy made significant progress in 2022 to improve its balance sheet and strengthen its credit profile. Using the proceeds from several equity transactions, approximately $2.6 billion of FirstEnergy holding company debt was eliminated. This includes the early retirement of an $850 million note in January, a $500 million note in June, and the repurchase of approximately $1.25 billion in high-coupon notes through a combination of tender offers and open-market repurchases. On a generally accepted accounting principles or "GAAP" basis, these accomplishments surpass the original plan for holding company debt reduction and brings FirstEnergy debt as percentage of total debt to 26% at the end of 2022 as compared to 33% at the end of 2021. Based on Moody's methodology, FirstEnergy had Cash Flow From Operations Before Changes To Working Capital to Debt ("CFO pre-WC to Debt Ratio") of just under 11% in 2022 and expects to be above Moody's CFO pre-WC to Debt Ratio upgrade threshold (at or above 11%) in 2023.

On February 2, 2023, FirstEnergy agreed to sell an incremental 30% equity interest in FirstEnergy Transmission, LLC for a purchase price of $3.5 billion. The transaction is expected to close in the first quarter of 2024, subject to regulatory approvals. FirstEnergy intends to deploy the proceeds with a priority on further strengthening the balance sheet while also providing capital for higher levels of future regulated investments.

Q. With respect to JCP&L, was the creation of a standalone credit facility effective in diminishing the financial linkage with FirstEnergy?

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A. Yes. The day following FirstEnergy's completion of establishing six individual credit facilities, S&P raised the Issuer Credit Rating to BB+ from BB and the Senior Unsecured Credit Ratings from BB+ to BBB- for JCP&L and others.[2] Relative to JCP&L and other affiliates, on page 2 of its October 19, 2021 Research Update, as rationale for its ratings upgrade, S&P stated: "The new credit facility agreements supplement the existing separateness and insulating measures already in place. As such, we assess the cumulative ring-fencing measures as sufficient to rate the utilities one notch above the GCP [Group Credit Profile]" (See Schedule BW-5).

Q. What financial metrics do the NRSROs review to assign credit ratings?

A. Each NRSRO has its own ratings methodology that considers several financial metrics in determining an entity's credit rating. The financial metrics reviewed may include: EBIT (Earnings Before Income Taxes) Interest Coverage; Return on Capital; and some measure of cash flow from operations as a ratio to debt, such as CFO pre-WC to Debt Ratio. The cash flow from operations as a ratio of debt metric is an important metric commonly relied upon as a basis to establish credit ratings. In addition to these key financial metrics, there are other qualitative factors or ratings qualifiers that are then applied to determine the credit rating. These qualifiers may include regulatory environment, operating performance and efficiency, corporate governance, and industry and/or company specific risks.

Q. Please explain the CFO pre-WC to Debt Ratio referenced above.

[2] https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/2740605

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A. CFO pre-WC to Debt Ratio is a metric used by Moody's. Generally, the CFO pre-WC to Debt ratio is a measure of cash flow from operations as compared to the total short-term and long-term debt outstanding, expressed as a percentage. This methodology calls for certain adjustments to both cash flows from operations and debt in the calculation of this ratio. For purposes of my testimony, I will use the CFO pre-WC to Debt Ratio to discuss the impacts of large expenditures and the associated rate recovery on JCP&L's CFO pre-WC to Debt Ratio.

Q. Given that JCP&L's recent and forecasted performance with respect to the CFO pre-WC to Debt Ratio is below the threshold of 19% for an A3 rating, is there potential for any ratings changes at JCP&L?

A. Not without improvements to cost recovery. Moody's has recently cited storm costs in 2020 and regulatory lag associated with cost recovery in 2020 and 2021 as pressuring JCP&L's credit metrics. Going forward, the funding and recovery of JCP&L's large, deferred storm cost balance, advanced metering infrastructure deployment (AMI, i.e., smart meters) and electric vehicle (EV) programs through base rate deferral mechanisms also pressure JCP&L's CFO pre-WC to Debt Ratio. Based on the Company's financial forecast for 2023 – 2025, JCP&L likely will not be able to attain and maintain a CFO pre-WC to Debt Ratio above the 19% necessary to support Moody's current rating of A3. In fact, without improvements to cash flows to support JCP&L's credit metrics, a negative credit action by Moody's may occur.

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EXHIBIT JC-6

Q. How does the $310 million[3] deferred storm balance negatively impact credit ratings?

A. The deferred storm balance impacts JCP&L's credit metrics in two ways. First, a major storm is an anomalous event and the cost of extensive restoration efforts often outstrip available "cash on hand." In such circumstances, JCP&L borrows on a short-term basis, generally first from the FirstEnergy Regulated Money Pool, to fund the cash cost of storm restoration, including both capital and operation and maintenance ("O&M") costs. The increased debt to fund storm restoration increases the denominator in the calculation of the CFO pre-WC to Debt Ratio. A higher denominator lowers the resulting ratio. Second, JCP&L receives no current recovery of carrying costs on its deferred storm balance, which lowers the numerator. A lower numerator in the calculation of the CFO pre-WC to Debt Ratio metric lowers the resulting ratio. Including and recovering a carrying charge on the deferred storm balance and/or simply increasing recovery of the deferred storm balance in base rates would increase the resulting CFO pre-WC to Debt Ratio and be more credit supportive for JCP&L.

Q. To the extent JCP&L finances storm restoration costs with short-term debt, why would it impact the CFO pre-WC to Debt Ratio?

A. For regulatory purposes, "debt" usually refers to borrowing to provide for long-term capitalization of rate base. For purposes of establishing credit ratings, the rating agency methodologies include both short-term and long-term debt as "debt", and for Moody's, the CFO pre-WC to Debt Ratio. Therefore, deferred storm costs,

[3] As of December 31, 2022.

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to the extent they are funded by short-term and/or long-term debt, adversely impact the CFO pre-WC to Debt Ratio.

Q. What determines how JCP&L finances its deferred storm balance?

A. JCP&L does not issue debt or assign tranches of debt specifically to finance storm costs. JCP&L uses a combination of short-term and long-term debt to meet the cash requirements for operations, capital investments and general business purposes of JCP&L, including funding storm restoration. As storm events occur, JCP&L generally first uses cash on hand to fund the restoration efforts. To the extent that additional funding is required, JCP&L relies on short-term debt, generally first sourced from the FirstEnergy Regulated Money Pool, which is JCP&L's least expensive source of liquidity. As discussed, JCP&L has its own $500 million revolving credit facility. JCP&L's short-term debt authority is currently $500 million total, so borrowing from the money pool and the revolving credit facility, in combination, cannot exceed $500 million. Should JCP&L approach its short-term debt limit, JCP&L would petition the BPU for authority to issue long-term debt and convert such outstanding short-term debt to long-term debt, thus restoring its short-term borrowing capacity. Therefore, depending on the cost of an event, the period of time that JCP&L carries the deferred storm costs on its books and the timing of its long-term debt issuance, some or all of the costs of major storm events may be financed with long-term debt.

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EXHIBIT JC-6

Q. How do the AMI and EV Program investments and the associated rate recovery affect JCP&L's credit ratings?

A. When JCP&L can finance its capital investments with cash generated from operations, it can operate with no additional debt requirements. However, to the extent that there are cash requirements that cause JCP&L to be cash flow negative, JCP&L will need to raise capital. Therefore, to the extent that debt financing is used, there will be impacts on the CFO pre-WC to Debt Ratio, depending on the magnitude of these incremental cash requirements and the timeliness of the rate recovery associated with these incremental cash expenditures.

During the 2023 - 2025 forecast horizon, JCP&L has significant cash requirements to fund its AMI and EV Programs. JCP&L has also announced its plans to file an infrastructure investment program ("IIP") later this year. Recovery of AMI and EV Program costs is through deferral mechanisms that delay recovery to future base rate cases. As these costs are in addition to JCP&L's base capital and O&M budgets, JCP&L will need to raise capital to fund these programs as well. Higher levels of investment require increased borrowings at JCP&L and with substantial recovery being deferred until a future base rate case, the CFO pre-WC to Debt Ratio will be negatively impacted.

With respect to AMI deployment, the cash requirement includes $390 million for plant in service, $73.3 million for O&M, and $30.8 million in Cost of Removal, for a total of $494.1 million. The Deployment Phase of JCP&L's AMI Plan is to occur over a three-year period from 2023 - 2025. As a result, there are

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significant cash requirements at JCP&L from 2023 - 2025, which pressure JCP&L's CFO pre-WC to Debt Ratio from this effort alone.

With respect to its Light Duty EV Program, JCP&L's cash requirements from July 2022 through June 2026 are budgeted to be $39.9 million. The cash requirements and the impacts to CFO pre-WC to Debt Ratio as a result of the Light Duty EV Program itself are not significant. However, cash requirements for this program are additive to cash requirements during a time period where there are very significant cash requirements to finance deferred storm costs and other required capital investments, such as AMI deployment, a second IIP, and the medium and heavy-duty EV program anticipated to be undertaken by JCP&L.

Q. Does JCP&L's request in the instant filing include recovery of the AMI and Light Duty EV Program costs?

A. Yes, it does. JCP&L is requesting recovery of its AMI Investment and O&M deferred regulatory assets based on a 10-year amortization, which results in a $1.8 million test year adjustment (See testimony of Carol Pittavino, Schedule CAP-2, Adjustment 11). Also, JCP&L is requesting recovery of the EV deferred regulatory assets based on a five-year amortization, which results in a $445,552 test year adjustment (See testimony of Carol Pittavino, Schedule CAP-2, Adjustment 9).

Q. What is JCP&L requesting of the BPU to further support JCP&L's current credit ratings?

A. Setting aside the Company's general rate increase request, JCP&L is asking that the BPU recognize in its deliberations that the lag in recovery that is present for

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capital intensive, and in some cases accelerated, investments such as those described above are not only impactful to JCP&L's cash flows, but also drive negative and very real downstream impacts to its credit metrics and, ultimately, debt costs paid by customers. In the instant case, granting the Company's requests for recovery of the AMI and Light Duty EV Program amortizations, as well as the requested increase in storm cost recovery, as proposed, would be a credit supportive step for JCP&L. Further, an increase in storm amortization would enable JCP&L to use the cash from deferred storm cost recovery to fund these required capital investments, in turn reducing the level of forecasted borrowings and, thereby, pressure on its credit ratings.

Q. Does this conclude your direct testimony?

A. Yes.

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Schedule BW-1

FirstEnergy Corp.
Capitalization

(in millions)	Pro Forma 9/30/2023	%
Total Equity	11,036	32.4%
Long-term Debt	21,726	63.9%
Securitized Debt	400	1.2%
Short-term Borrowings	862	2.5%
Total Capitalization	**$ 34,024**	**100.0%**

JCP&L
Capitalization

(in millions)	Pro Forma 9/30/2023	As Adjusted	Adjusted as of 9/30/2023	%
Short-Term Borrowings	299	(299)	-	0%
			-	0%
Total Equity	4,128	-	4,128	65.8%
Long-term Debt	2,150	-	2,150	34.2%
Total Capitalization	**$ 6,577**	**$ (299)**	**$ 6,278**	**100%**

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Schedule BW-2

JCP&L
Capitalization

(in millions)	Adjusted as of 9/30/2023	Exclude Goodwill	Adjusted as of 9/30/2023	%
Total Equity	4,128	(1,811)	2,318	51.9%
Long-term Debt	2,150		2,150	48.1%
Total Capitalization	**$ 6,278**	**$ (1,811)**	**$ 4,467**	**100.0%**

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Schedule BW-3

JCP&L
Computation of Long Term Debt Embedded Cost
9/30/2023

Debt Issue	Date of Issue	Date of Maturity	(1) Original Principal Amount	(2) Amount Outstanding	(3) Premium or (Discount) at Issuance	(4) Issuance Expenses	(5) Net Proceeds (1)+(3)-(4)	(6) Net Proceeds Ratio (5)/(1)	(7) Embedded Rate	(8) Embedded Cost (7)*(9)	(9) Adjusted Amount Outstanding (2)*(6)
6.40% Senior Notes	5/12/2006	5/15/2036	200,000,000	200,000,000	(1,216,000)	2,346,872	196,437,128	98.2186	6.536%	12,839,410	196,437,128
6.15% Uns Notes	5/16/2007	6/1/2037	300,000,000	300,000,000	(3,693,000)	327,220	295,979,780	98.6599	6.249%	18,496,143	295,979,780
4.70% Uns Notes	8/21/2013	4/1/2024	500,000,000	500,000,000	(2,595,000)	4,207,350	493,197,650	98.6395	4.865%	23,994,383	493,197,650
4.30% Senior Notes	8/18/2015	1/15/2026	250,000,000	250,000,000	(800,000)	2,113,488	247,086,512	98.8346	4.441%	10,972,171	247,086,512
4.30% Senior Notes	2/8/2019	1/15/2026	400,000,000	400,000,000	5,884,000	3,018,783	402,865,217	100.7163	4.180%	16,837,972	402,865,217
2.75% Senior Notes	6/10/2021	3/1/2032	500,000,000	500,000,000	(1,370,000)	4,509,046	494,120,954	98.8242	2.878%	14,220,488	494,120,954
Sub - Totals				**$2,150,000,000**						**$ 97,360,567**	**$ 2,129,687,240**

Weighted Cost (8) / (9)

Weighted Cost of Long-Term Debt	4.572%

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Schedule BW-4

JCP&L
Weighted Average Cost of Capital

	Ratios	Embedded Cost	Weighted Average Cost of Capital
Total Equity	51.9%	10.40%	5.40%
Long-term Debt	48.1%	4.57%	2.20%
Total Capitalization	100.0%		7.60%

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S&P Global
Ratings

Research

Research Update:

FirstEnergy Corp. Subsidiary Ratings Raised; On CreditWatch Positive

October 19, 2021

Rating Action Overview

On Oct 8 202 F rstEnergy Corp (FE) created s x d st nct f ve year sen or nsec red comm tted cred t fac t es to rep ace the company s two prev o s cred t fac t es mat r ng December 2022

S&P G oba Rat ngs be eves th s meas re s pp ements the ex st ng ns at ng meas res n p ace C m at ve y we v ew the str ct ra protect ons and the strength of each operat ng s bs d ar es stand a one cred t prof es as s ff c ent to rate FE s reg ated t t es p to one notch h gher than FE s gro p cred t prof e (GCP)

We are ra s ng o r ss er cred t rat ngs (CRs) to BB+ from BB on Amer can ransm ss on Systems nc (A S) C eve and E ectr c m nat ng Co (CE) Jersey Centra Power & ght Co (JCP&) M d At ant c nterstate ransm ss on C (MA) Metropo tan Ed son Co (MetEd) Monongahe a Power Co (MonPower) Oh o Ed son Co (OE) Potomac Ed son Co (PE) Pennsy van a E ectr c Co (Pene ec) Pennsy van a Power Co (Penn Power) o edo Ed son Co (E) rans A egheny nterstate ne Co (rA) and West Penn Power Co (WPP)

We are aff rm ng a rat ngs at FE and F rstEnergy ransm ss on C (FE) nc d ng the BB CR the BB sen or nsec red debt rat ngs and the B+ preferred stock ss e eve rat ngs at FE

We are ra s ng the sen or sec red ss e eve rat ngs at CE OE E Penn Power WPP PE and MonPower to BBB+ from BBB ref ect ng a + recovery rat ng We are a so ra s ng the sen or nsec red rat ngs to BBB from BB+ at CE OE MetEd Pene ec JCP& MonPower A S MA and rA

he rat ngs on FE and ts s bs d ar es rema n on Cred tWatch w th pos t ve mp cat ons wh ch ref ects the probab ty that we co d ra se the rat ng by one or more notches n the com ng months based on today s anno ncement and f the company dent f es ts ong term f nd ng for ts potent a pena t es and f nes or t reso ves the rema n ng nvest gat ons and aws ts aga nst the company w tho t weaken ng cred t q a ty

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Rating Action Rationale

We are upgrading ATSI, CEI, JCP&L, MAIT, MetEd, MonPower, OE, PE, Penelec, Penn Power, TE, TrAIL, and WPP, to 'BB+' from 'BB'. The new cred t fac ty agreements supp ement the ex st ng separateness and nsu at ng measures a ready n p ace As such we assess the cumu at ve r ng-fenc ng measures as suff c ent to rate the ut t es one notch above the GCP Key nsu at ng measures nc ude:

- Each ut ty s a separate stand-a one ega ent ty that funct ons ndependent y (both f nanc a y and operat ona y) f es ts own rate cases and s ndependent y regu ated
- Each ut ty has ts own records and books nc ud ng stand-a one aud ted f nanc a statements;
- Each ut ty has ts own fund ng arrangements ssues ts own ong-term debt and has a d st nct sub m t under ts comm tted cred t fac ty for ts short-term fund ng needs;
- Wh e the ut t es can borrow from FE or FET ne ther of the ho d ng compan es can borrow from any of the regu ated ut t es;
- We be eve there s a strong econom c bas s for FE to preserve the ent t es cred t strength wh ch ref ects the ut t es ow-r sk prof tab e regu ated nature and that they const tute the major ty of FE s operat ons; and
- There are no cross-defau t prov s ons between the ut t es and FE or FET that cou d d rect y ead to a defau t at the ent t es

There are no changes to our recovery ratings. The sen or unsecured debt rat ngs at FE and FET are ba ed on our 3 recovery rat ngs nd cat ng our expectat on of mean ngfu (50%-70%; rounded est mate: 65%) recovery n the event of a payment defau t The recovery rat ng on th s debt s capped at 3 cons stent w th our approach for ass gn ng recovery rat ngs to unsecured debt ssued by BB category corporate ent t es because recovery prospects are h gh y vu nerab e to mpa rment before defau t by add t ona debt ssuance

The recovery rat ng for CE OE TE and MonPower s sen or secured f rst-mortgage bonds s 1+ Key ana yt ca factors nc ude:

- Our 1+ recovery rat ng on the sen or ecured f rst-mortgage bonds ref ects that the va ue of ts regu ated ut ty assets s suff c ent y arger than the va ue of ts secured debt
- The recovery rat ng nd cates our h ghest expectat on for fu recovery and resu ts n an ssue- eve rat ng three notches above our ssuer cred t rat ng t a so ref ects the bonds co atera coverage n excess of 150% wh ch s cons stent w th our cr ter a for recovery rat ngs on debt ssued by regu ated ut t es and ecured by key ut ty assets
- A defau t cou d occur due to sudden qu d ty pressures am d an unpred ctab e weather cost or market event outs de the company s contro wh ch s cons stent w th the cond t ons of past ut ty defau ts Furthermore t cou d ref ect s gn f cant future t gat on exposure pend ng the outcomes of the mu t p e ongo ng nvest gat ons cr m na a egat ons and c v awsu ts at parent FE
- We expect the ent t es wou d cont nue to operate and reorgan ze after defau t ng g ven the es ent a nature of ts serv ces We a so assume the va ue of the ut ty s assets w be preserved We use the net va ue of ts regu ated f xed assets as a proxy for ts enterpr se va ue We ca cu ate FE s regu ated asset va ue as rough y $33 b on

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The recovery rat ng on the ATS CE JCP& MA T MetEd MonPower OE Pene ec and TrA sen or unsecured ssues s 2 Th s s nd cat ve of our expectat on of substant a (70%-90%; rounded est mate: 85%) recovery n the event of a payment defau t The recovery rat ng on th s debt s capped at 2 cons stent w th our approach for ass gn ng recovery rat ngs to unsecured debt ssued by BB category regu ated ut t es because recovery prospects are somewhat vu nerab e to mpa rment before defau t by add t ona debt ssuance

CreditWatch

We expect to reso ve the Cred tWatch p acement n the com ng months f the company dent f es ts ong-term fund ng for ts potent a pena t es and f nes or t reso ves the rema n ng nvest gat ons and awsu ts w thout weaken ng cred t qua ty We expect the company w cont nue to mprove ts nterna contro s and demonstrate mproved governance and cu ture Effect ve management of these ssues cou d ke y resu t n an upgrade of one or more notches

A though un ke y we cou d remove the rat ngs from Cred tWatch w th pos t ve mp cat ons and aff rm the rat ngs f bus ness r sk ncreases such as a weaken ng of the company s ab ty to cons stent y manage regu atory r sk or f quest ons rema n about the fund ng of potent a pena t es and f nes or f f nanc a measures weaken ref ect ng funds from operat ons cons stent y be ow 9%

Ratings Score Snapshot

FirstEnergy Corp.

ssuer cred t rat ng: BB/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: Aggress ve

- Cash f ow/ everage: Aggress ve

Anchor: bbb

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Negat ve (-1 notch)

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Stand-a one cred t prof e: bb

- Group cred t prof e: bb

FirstEnergy Transmission LLC

ssuer Cred t Rat ng: BB/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: ntermed ate

- Cash f ow/ everage: ntermed ate

Anchor: a+

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Negat ve (-1 notch)

Stand-a one cred t prof e: bbb+

- Group cred t prof e: bb
- Ent ty status w th n group: Core (-4 notches from SACP)

American Transmission Systems Inc.

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: ntermed ate

- Cash f ow/ everage: ntermed ate

Anchor: a+

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Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: a-

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Cleveland Electric Illuminating Co.

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: S gn f cant

- Cash f ow/ everage: S gn f cant

Anchor: a-

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bbb

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Jersey Central Power & Light Co.

ssuer Cred t Rat ng: BB+/Watch Pos/NR

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Bus ness r sk: Strong

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Sat sfactory

F nanc a r sk: S gn f cant

- Cash f ow/ everage: S gn f cant

Anchor: bbb

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bb+

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Metropolitan Edison Co.

ssuer Cred t Rat ng: BB+/Watch Pos/NR

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: S gn f cant

- Cash f ow/ everage: S gn f cant

Anchor: a-

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)

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- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bbb

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Mid-Atlantic Interstate Transmission LLC

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Exce ent

F nanc a r sk: ntermed ate

- Cash f ow/ everage: ntermed ate

Anchor: a+

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: a-

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Monongahela Power Co.

ssuer Cred t Rat ng: BB+/Watch Pos/NR

Bus ness r sk: Strong

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Sat sfactory

F nanc a r sk: S gn f cant

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- Cash f ow/ everage: S gn f cant

Anchor: bbb

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bb+

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Ohio Edison Co.

ssuer Cred t Rat ng: BB+/Watch Pos/B

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: Modest

- Cash f ow/ everage: Modest

Anchor: aa

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Negat ve (-1 notch)

Stand-a one cred t prof e: a

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

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Pennsylvania Electric Co.

ssuer Cred t Rat ng: BB+/Watch Pos/NR

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: S gn f cant

- Cash f ow/ everage: S gn f cant

Anchor: a-

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bbb

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Pennsylvania Power Co.

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: ntermed ate

- Cash f ow/ everage: ntermed ate

Anchor: a+

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)

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- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: a-

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Potomac Edison Co.

ssuer Cred t Rat ng: BB+/Watch Pos/NR

Bus ness r sk: Strong

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Sat sfactory

F nanc a r sk: S gn f cant

- Cash f ow/ everage: S gn f cant

Anchor: bbb

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bb+

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Toledo Edison Co.

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow

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- Compet t ve pos t on: Strong

F nanc a r sk: S gn f cant

- Cash f ow/ everage: S gn f cant

Anchor: a-

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: bbb

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Trans-Allegheny Interstate Line Co.

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Exce ent

F nanc a r sk: Modest

- Cash f ow/ everage: Modest

Anchor: aa

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Neutra (no mpact)

Stand-a one cred t prof e: a+

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- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

West Penn Power Co.

ssuer Cred t Rat ng: BB+/Watch Pos/--

Bus ness r sk: Exce ent

- Country r sk: Very ow
- ndustry r sk: Very ow
- Compet t ve pos t on: Strong

F nanc a r sk: ntermed ate

- Cash f ow/ everage: ntermed ate

Anchor: a+

Mod f ers:

- D vers f cat on/portfo o effect: Neutra (no mpact)
- Cap ta structure: Neutra (no mpact)
- F nanc a po cy: Neutra (no mpact)
- qu d ty: Adequate (no mpact)
- Management and governance: Weak (-2 notches)
- Comparab e rat ng ana ys s: Negat ve (-1 notch)

Stand-a one cred t prof e: bbb+

- Group cred t prof e: bb
- Ent ty status w th n group: nsu ated

Related Criteria

- Genera Cr ter a: Env ronmenta Soc a And Governance Pr nc p es n Cred t Rat ngs Oct 10 2021
- Genera Cr ter a: Group Rat ng Methodo ogy Ju y 1 2019
- Genera Cr ter a: Hybr d Cap ta : Methodo ogy And Assumpt ons Ju y 1 2019
- Cr ter a Corporates Genera : Corporate Methodo ogy: Rat os And Adjustments Apr 1 2019
- Genera Cr ter a: Methodo ogy For nk ng ong-Term And Short-Term Rat ngs Apr 7 2017
- Cr ter a Corporates Genera : Recovery Rat ng Cr ter a For Specu at ve-Grade Corporate ssuers Dec 7 2016
- Cr ter a Corporates Genera : Methodo ogy And Assumpt ons: qu d ty Descr ptors For G oba Corporate ssuers Dec 16 2014

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- Genera Cr ter a: Methodo ogy: ndustry R sk Nov 19 2013
- Cr ter a Corporates Genera : Corporate Methodo ogy Nov 19 2013
- Cr ter a Corporates Ut t es: Key Cred t Factors For The Regu ated Ut t es ndustry Nov 19 2013
- Genera Cr ter a: Country R sk As essment Methodo ogy And Assumpt ons Nov 19 2013
- Genera Cr ter a: Methodo ogy: Management And Governance Cred t Factors For Corporate Ent t es Nov 13 2012
- Genera Cr ter a: Pr nc p es Of Cred t Rat ngs Feb 16 2011

Related Research

- Research Update: F rstEnergy Corp And Subs d ar es Rat ngs On Cred tWatch Pos t ve Fo ow ng Deferred Prosecut on Agreement Ju y 23 2021

Ratings List

Ratings Affirmed		
FirstEnergy Corp.		
FirstEnergy Transmission LLC		
ssue C ed Ra g	BB/Wa c os/	
Ratings Upgraded		
	To	**From**
American Transmission Systems Inc.		
Trans Allegheny Interstate Line Co.		
Toledo Edison Co.		
Pennsylvania Power Co.		
Mid Atlantic Interstate Transmission LLC		
Cleveland Electric Illuminating Co.		
Jersey Central Power & Light Co.		
West Penn Power Co.		
Potomac Edison Co.		
Pennsylvania Electric Co.		
Monongahela Power Co.		
Metropolitan Edison Co.		
ssue C ed Ra g	BB /Wa c os/	BB/Wa c os/
Ohio Edison Co.		
ssue C ed Ra g	BB /Wa c os/B	BB/Wa c os/B

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Issue Level Ratings Affirmed Recovery Ratings Unchanged		
FirstEnergy Corp.		
Se o U secu ed	BB/Wa c os	
Recove y Ra g	3(65%)	
e e ed S ock	B /Wa c os	
FirstEnergy Transmission LLC		
Se o U secu ed	BB/Wa c os	
Recove y Ra g	3(65%)	
Issue Level Ratings Raised Recovery Ratings Unchanged		
American Transmission Systems Inc.		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Cleveland Electric Illuminating Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os
Recove y Ra g		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Jersey Central Power & Light Co.		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Metropolitan Edison Co.		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Mid Atlantic Interstate Transmission LLC		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Monongahela Power Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os
Recove y Ra g		
Ohio Edison Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os
Recove y Ra g		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Pennsylvania Electric Co.		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
Pennsylvania Power Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os

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Recove y Ra g		
Potomac Edison Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os
Recove y Ra g		
Toledo Edison Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os
Recove y Ra g		
Trans Allegheny Interstate Line Co.		
Se o U secu ed	BBB /Wa c os	BB /Wa c os
Recove y Ra g	2(85%)	2(85%)
West Penn Power Co.		
Se o Secu ed	BBB /Wa c os	BBB/Wa c os
Recove y Ra g		

Ce a e ms used s e o a cu a yce a ad ec ves used o ex ess ou v ew o a g e eva ac o s ave s ec c mea gs asc ed o em ou c e a a ds ou d e e o e e ead co u c o w suc c e a ease see Ra gs C e a a www s a da da d oo s com o u e o ma o Com e e a gs o ma o sava a e o su sc e s o Ra gsD ec a www ca a q com A a gs a ec ed y s a g ac o ca e ou d o S& G o a Ra gs u c we s e a www s a da da d oo s com Use e Ra gs sea c ox oca ed e e co um

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o the extent that reg atory a thor t es a ow a rat ng agency to acknow edge n one r sd ct on a rat ng ss ed n another r sd ct on for ce ta n reg atory p rposes S&P reserves the r ght to ass gn w thdraw or s spend s ch acknow edgment at any t me and n ts so e d scret on S&P Pa t es d sc a m any d ty whatsoever ar s ng o t of the ass gnment w thdrawa or s spens on of an acknow edgment as we as any ab ty for any damage a eged to have been s ffered on acco nt thereof

S&P keeps certa n act v t es of ts b s ness n ts separate from each other n order to preserve the ndependence and ob ect v ty of the r respect ve act v t es As a res t ce ta n b s ness n ts of S&P may have nformat on that s not ava ab e to other S&P b s ness n ts S&P has estab shed po c es and proced res to ma nta n the conf dent a ty of certa n non p b c nformat on rece ved n connect on w th each ana yt ca process

S&P may rece ve compensat on for ts rat ngs and ce ta n ana yses norma y from ss ers or nderwr ters of sec r t es or from ob gors S&P reserves the r ght to d ssem nate ts op n ons and ana yses S&P s p b c rat ngs and ana yses are made ava ab e on ts Web s tes www standardandpoors com (free of charge) and www rat ngsd rect com and www g oba cred tporta com (s bscr pt on) and may be d str b ted thro gh other means nc d ng v a S&P p b cat ons and th rd pa ty red str b tors Add t ona nformat on abo t o r rat ngs fees s ava ab e at www standardandpoors com/ srat ngsfees

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State Corporation Commission
of Kansas

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

ANN E. BULKLEY

ON BEHALF OF EVERGY METRO, INC., EVERGY KANSAS CENTRAL, INC. AND EVERGY KANSAS SOUTH, INC.

IN THE MATTER OF THE APPLICATION OF EVERGY KANSAS METRO, INC., EVERGY KANSAS SOUTH, INC. AND EKC, INC. TO MAKE CERTAIN CHANGES IN THEIR CHARGES FOR ELECTRIC SERVICE PURSUANT TO K.S.A. 66-117.

Docket No. 23-EKCE-775-RTS

April 25, 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q: Please state your name, by whom you are employed, and your business address.

A: My name is Ann E. Bulkley. I am a Principal at The Brattle Group ("Brattle"). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q: On whose behalf are you submitting this testimony?

A: I am submitting this direct testimony before the State Corporation Commission of the State of Kansas ("Commission") on behalf of Evergy Kansas Central, Inc., Evergy Kansas South, Inc., and Evergy Metro, Inc., wholly-owned subsidiaries of Evergy, Inc. Evergy Kansas Central, Inc. and Evergy Kansas South, Inc., are referred to collectively herein as "EKC", and Evergy Metro, Inc.'s Kansas operations are referred to herein as Evergy Kansas Metro ("EKM"). I will refer to EKM and EKC collectively as "the Companies".

Q: Please describe your background and professional experience in the energy and utility industries.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 25 years of experience consulting to the energy industry. I have provided testimony regarding financial matters, including the cost of capital, before multiple regulatory agencies. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. A summary of my professional background and a listing of the testimony that I have filed in other proceedings is presented in **Attachment A.**

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II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q: What is the purpose of your direct testimony?

A: The purpose of my direct testimony is to present evidence and provide an opinion regarding the reasonableness of the Companies' requested return on equity ("ROE") for the Companies' electric utility operations in Kansas and to provide an assessment of the proposed capital structure to be used for ratemaking purposes.

Q: Are you sponsoring any exhibits in support of your direct testimony?

A: Yes. My analyses and recommendations are supported by the data presented in **Exhibits AEB-1 through AEB-14**, which have been prepared by me or under my direction.

Q: Please provide a brief overview of the analyses that led to your ROE recommendation.

A: I have estimated the Companies' cost of equity by applying several traditional estimation methodologies to a proxy group of comparable utilities, including the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and the Risk Premium approach. My recommendation also takes into consideration: (1) the regulatory environment in which the Companies operate; (2) the Companies' capital expenditure requirements; and (3) the Companies' planned investments in renewable generation assets compared to its current generation portfolio. Finally, I consider the Companies' proposed capital structure as compared to the capital structures of the proxy companies. While I did not make any specific adjustments to my cost of equity estimates for any of these factors, I did consider them in the aggregate when determining the reasonableness of where the Companies' requested ROE falls within the range of the analytical results.

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Q: How is the remainder of your direct testimony organized?

A: The remainder of my direct testimony is organized as follows:

- Section III provides a summary of my analyses and conclusions.
- Section IV reviews the regulatory principles pertinent to the development of the cost of capital.
- Section V discusses current and projected capital market conditions and the effect of those conditions on the Companies' cost of equity.
- Section VI summarizes recently authorized ROEs in other jurisdictions.
- Section VII explains my selection of proxy group of electric utilities.
- Section VIII describes my analyses and the analytical basis for my recommendation of the appropriate ROE for the Companies.
- Section IX provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Companies in this case.
- Section X discusses the capital structure of the Companies as compared with the proxy group.
- Section XI presents my conclusions and recommendations for the market cost of equity.

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III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q: Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A: My analyses and recommendations considered the following:

- The United States Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.
- The effect of current and projected capital market conditions on investors' return requirements.
- The results of several analytical approaches that provide estimates of the Companies' cost of equity. Because the Companies' required ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis).
- Although the proxy group companies are generally comparable to EKC and EKM, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Companies' regulatory, business, and financial risks relative to the proxy group in determining where the

[1] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

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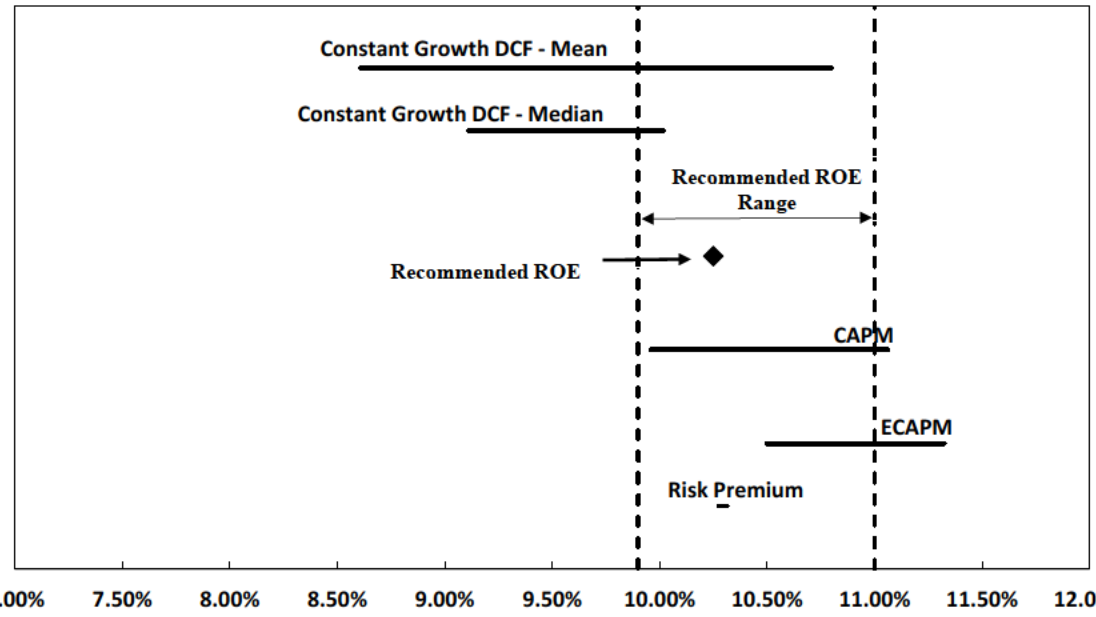
Companies' ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

Q: What are the results of the models that you have used to estimate the cost of equity for the Companies?

A: Figure 1 summarizes the range of results produced by the DCF, CAPM, ECAPM and Risk Premium analyses based on data through to the end of March 2023.

Figure 1: Summary of Cost of Equity Analytical Results



As shown in Figure 1, (and in **Exhibit AEB-1**), the range of results produced by the COE estimation models is wide. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

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Q: How are prospective capital market conditions expected to affect the results of the cost of equity for the Companies during the period in which the rates established in this proceeding will be in effect?

A: Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models in the following ways:

- Inflation is expected to persist over the near-term, which increases the operating risk of the utility during the period in which rates will be in effect.
- Long-term interest rates have increased substantially in the past year and are expected to remain relatively high at least over the next year in response to inflation.
- Since utility dividend yields are now less attractive than the risk-free rates of government bonds, and interest rates are expected to remain near current levels over the next year, and since utility stock prices are inversely related to changes in interest rates, it is likely that utility share prices will decline.
- Rating agencies have responded to the risks of the utility sector, with Moody's Investors Service ("Moody's") most recently indicating its outlook for the industry in 2023 is "negative", citing increasing interest rates, inflation and high natural gas prices, all of which create pressure for customer affordability and prompt rate recovery.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of rising interest rates and expect the sector to underperform over the near-term.

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- Consequently, the results of the DCF model, which relies on current utility share prices, is likely to understate the cost of equity during the period that the Companies rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the recommended ROE for the Companies.

Q: What is your conclusion regarding the appropriate authorized ROE for the Companies in this proceeding?

A: Considering the analytical results presented in Figure 1, current and prospective capital market conditions, as well as the level of regulatory, business, and financial risk faced by the Companies' electric operations in Kansas relative to the proxy group, I believe a range of returns from 9.90 to 11.00 percent is reasonable. Within that range, the Companies are requesting a return of 10.25 percent, which is reasonable, if not conservative.

Q: Is the Companies' requested capital structure reasonable and appropriate?

A: The Companies' proposed equity ratios of 52.00 percent for EKM and 52.0376 percent for EKC are within the range of equity ratios for the proxy group, and generally at the average equity ratio for the group. Further, the Companies' proposed equity ratio is reasonable considering that credit rating agencies have identified the outlook for the utility sector as "negative" due to the negative effect on the cash flows and credit metrics associated with increasing interest rates, inflation and commodity costs, and the pressure that those factors place on customer affordability and utilities' prompt rate recovery.

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IV. REGULATORY PRINCIPLES

Q: Please describe the guiding principles to be used in establishing the cost of capital for a regulatory utility.

A: The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[2]

Q: Has the Commission provided similar guidance in establishing the appropriate ROE?

A: Yes, it has. In Docket No. 15-WSEE-115-RTS for Westar Energy, Inc. and Kansas Gas and Electric Company, the Commission recognized the Supreme Court's authority in *Hope* and *Bluefield* regarding a "fair rate of return":

> In addition to Kansas' own statutes and case law on the subject, the U.S. Supreme Court has established certain principles for the Commission to follow when reviewing rate change applications. Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm 'n of W Va., 262 U.S. 679 (1923), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944), provide what this Commission has referred to as the "capital attraction standard." …These standards taken together stand for the general idea that the return provided to a utility's investors should (1) be consistent with other businesses having similar risks and

[2] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

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(2) the adequacy of the return for servicing debt and paying dividends be able to support a utility's credit quality, access to capital, and financial integrity.[3]

This guidance is consistent with the principle that an allowed rate of return must be sufficient to enable regulated entities, such as the Companies, to attract capital on reasonable terms.

Q: Is fixing a fair rate of return just about protecting the utility's interests?

A: No. As the court noted in *Bluefield*, a proper rate of return not only assures "confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit [but also] enable[s the utility] to raise the money necessary for the proper discharge of its public duties."[4] As the Court went on to explain in *Hope*, "[t]he rate-making process … involves balancing of the investor and consumer interests."[5]

Q: Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A: An ROE that is adequate to attract capital at reasonable terms enables the Companies to provide safe, reliable electric utility service while maintaining its financial integrity. That return should be commensurate with returns required by investors elsewhere in the market for investments of comparable risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Companies' ability to attract capital at reasonable cost.

[3] Kansas Corporation Commission, Docket No. 15-WSEE-115-RTS, Order, September 24, 2015, at 25-26.

[4] *Bluefield*, 262 U.S. at 679, 693.

[5] *Hope*, 320 U.S. at 591, 603.

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Q: Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A: Yes. Utilities compete directly for capital with other investments of similar risk, which include other utilities. Therefore, the ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q: Is the regulatory framework, including the authorized ROE and equity ratio, important to the financial community?

A: Yes. The regulatory framework is one of the most important factors in debt and equity investors' assessments of risk. Specifically, regarding debt investors, credit rating agencies consider the authorized ROE and equity ratio for regulated utilities to be very important for two reasons: (1) they help determine the cash flows and credit metrics of the regulated utility; and (2) they provide an indication of the degree of regulatory support for credit quality in the jurisdiction. To the extent that the authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Not only do credit ratings affect the overall cost of borrowing they also act as a signal to equity investors about the risk of investing in the equity of a company.

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Q. What are your conclusions regarding the regulatory principles to be used in establishing the cost of capital in this proceeding?

A: The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Companies with a reasonable opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Companies, which is in the interest of both customers and shareholders.

V. CAPITAL MARKET CONDITIONS

Q: Why is it important to analyze capital market conditions?

A: The models used to estimate the cost of equity rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the cost of equity estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses current

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and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE and the recommended ROE for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q: What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A: The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

Q: What effect do current and prospective market conditions have on the cost of equity for the Companies?

A: As is discussed in more detail in the remainder of this section, the combination of persistently high inflation and the Federal Reserve's changes in monetary policy contribute to an expectation of increased market risk and an increase in the cost of the investor-required return. It is essential that these factors be considered in setting the forward-

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looking ROE. Inflation has recently been at some of the highest levels seen in approximately 40 years, and while inflation has declined from these recent peaks, it remains relatively high. Interest rates, which have increased significantly from pandemic-related lows seen in 2020, are expected to continue to remain relatively high in direct response to the Federal Reserve's use of monetary policy to combat inflation. Since there is a strong historical inverse correlation between interest rates and the share prices of utility stocks (*i.e.,* share prices of utility stocks typically fall when interest rates rise), it is reasonable to expect that investors' required return for utility companies will also increase. Therefore, cost of equity estimates based solely on current market conditions will understate the cost of equity required by investors during the future period that the Companies' rates determined in this proceeding will be in effect.

A. Inflationary Expectations in Current and Projected Capital Market Conditions

Q: Has inflation increased significantly over the past year?

A: Yes. As shown in Figure 2, the year-over-year ("YOY") change in the Consumer Price Index ("CPI") published by the Bureau of Labor Statistics has increased steadily since the beginning of 2021, rising from 1.37 percent in January 2021 to a high of 9.0 percent in June 2022, which was the largest 12-month increase since 1981 and significantly greater than any level seen since January 2008. As shown in Figure 2, since that time, while inflation has declined in response to the Federal Reserve's monetary policy, inflation continues to remain elevated.

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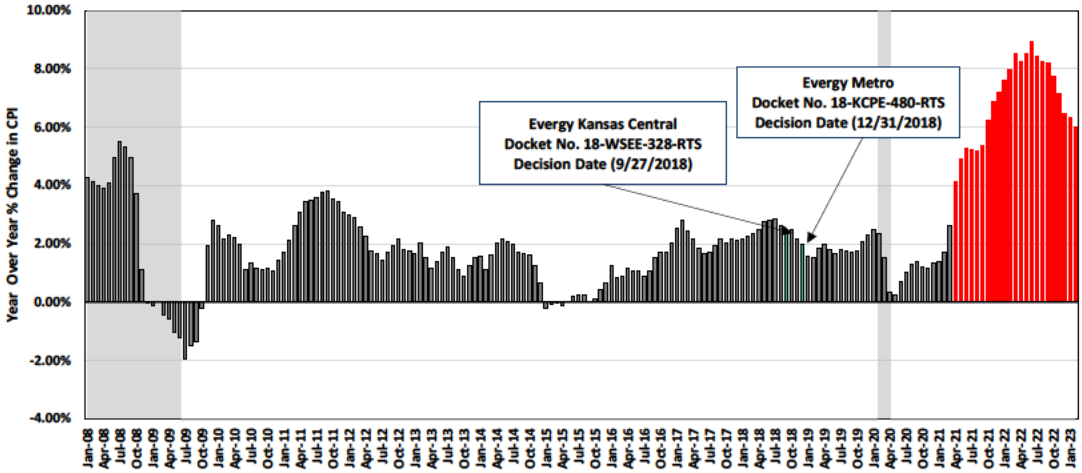
Figure 2: YOY Percent Change in the Consumer Price Index, January 2008 – February 2023[6]



Q: What are the expectations for inflation over the near term?

A: The Federal Reserve has indicated that it expects inflation will remain elevated above its target level over at least the next year and that it will continue to increase short-term interest rates to reduce inflation. For example, Federal Reserve Chair Powell at the Federal Open Market Committee ("FOMC") meeting in February 2023 anticipated further increases in the federal funds rate, and observed that while inflation is off of its recent highs, it remains significantly above the Federal Reserve's long-term target:

> We continue to anticipate that ongoing increases will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time.
>
> …..
>
> Inflation remains well above our longer-run goal of 2 percent. Over the 12 months ending in December, total PCE prices rose 5.0 percent; excluding the volatile food and energy categories, core PCE prices rose 4.4 percent. The inflation data received over the past three months show a welcome reduction in the monthly pace of increases. And while recent developments are encouraging, we will need substantially more evidence to be confident that inflation is on a sustained downward path.
>
> …..

[6] Bureau of Labor Statistics, shaded area indicates a recession.

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> With today's action, we have raised interest rates by 4-1/2 percentage points over the past year. We continue to anticipate that ongoing increases in the target range for the federal funds rate will be appropriate in order to attain a stance of monetary policy that is sufficiently restrictive to return inflation to 2 percent over time.
>
> …..
>
> At the December meeting, we all wrote down our best estimates of what we thought the ultimate level would be [of the federal funds rate], and that's obviously back in December. And the median for that was between five and five and a quarter percent. At the March meeting, we're going to update those assessments. We did not update them today. We did, however, continue to say that we believe ongoing rate hikes will be appropriate to attain a sufficiently restrictive stance of policy to bring inflation back down to 2 percent. We think we've covered a lot of ground, and financial conditions have certainly tightened. I would say we still think there's work to do there. We haven't made a decision on exactly where that will be. I think, you know, we're going to be looking carefully at the incoming data between now and the March meeting and then the May meeting. I don't feel a lot of certainty about where that will be. It could certainly be higher than we're writing down right now. If we come to the view that we need to write down to -- you know, to move rates up beyond what we said in December we would certainly do that. At the same time, if the data come in, in the other direction then we'll -- you know, we'll make data-dependent decisions at coming meetings, of course.[7]

B. The Use of Monetary Policy to Address Inflation

Q: What policy actions has the Federal Reserve enacted to respond to increased inflation?

A: The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. As of the FOMC meeting on February 1, 2023, the Federal Reserve has taken the following actions:

- Completed its taper of Treasury bond and mortgage-backed securities purchases;[8]

[7] Transcript, Chair Powell Press Conference, February 1, 2023; clarification added.

[8] Federal Reserve Bank of New York, https://www newyorkfed.org/markets/domestic-market-operations/monetary-policy-implementation/treasury-securities/treasury-securities-operational-details#monthly-details.

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- Increased the target federal funds rate beginning in March 2022 through a series of increases from a target range of 0.00 to 0.25 percent to a target range of 4.50 percent to 4.75 percent;[9]
- Anticipates ongoing increases in the target range will be appropriate to achieve its goals of maximum employment at the inflation rate of 2.00 percent over the long-run;[10]
- Began reducing its holdings of Treasury and mortgage-backed securities on June 1, 2022.[11] The Federal Reserve is reducing the size of its balance sheet by only reinvesting principal payments on owned securities after the total amount of payments received exceeds a defined cap. For Treasury securities, the cap is set at $30 billion per month for the first three months and $60 billion per month after the first three months. The cap for mortgage-backed securities is set at $17.5 billion per month for the first three months and $35 billion per month thereafter.[12]

C. The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return

Q: What effect will inflation and the Federal Reserve's normalization of monetary policy have on long-term interest rates?

A: Inflation and the Federal Reserve's normalization of monetary policy are expected to result in long-term interest rates remaining relatively high over at least the next year.

[9] Federal Reserve. Press Releases, March 16, 2022; Transcript. Chair Powell Press Conference, February 1, 2023.

[10] Transcript. Chair Powell Press Conference, February 1, 2023.

[11] Federal Reserve. Press Release, May 4, 2022.

[12] Federal Reserve. "Plans for Reducing the Size of the Federal Reserve's Balance Sheet." Press Release, May 4, 2022.

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Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond. This risk increases the longer the duration of the bond. As a result, if investors expect inflation to remain relatively high, they will require higher yields to compensate for the increased risk of inflation, which means interest rates will also remain relatively high.

Q: Have the yields on long-term government bonds increased in response to inflation and the Federal Reserve's normalization of monetary policy?

A: Yes. At the FOMC meetings throughout 2022 and thus far into 2023, the Federal Reserve has continued to note its concerns over the sustained increased levels of inflation and has continued to accelerate the process of normalizing monetary policy to combat inflation. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bond has more than doubled, increasing from 1.47 percent on December 15, 2021, to 3.48 percent on March 31, 2023. The increase is due to the Federal Reserve's announcements at each of the meetings since December 2021 and the continued elevated levels of inflation.

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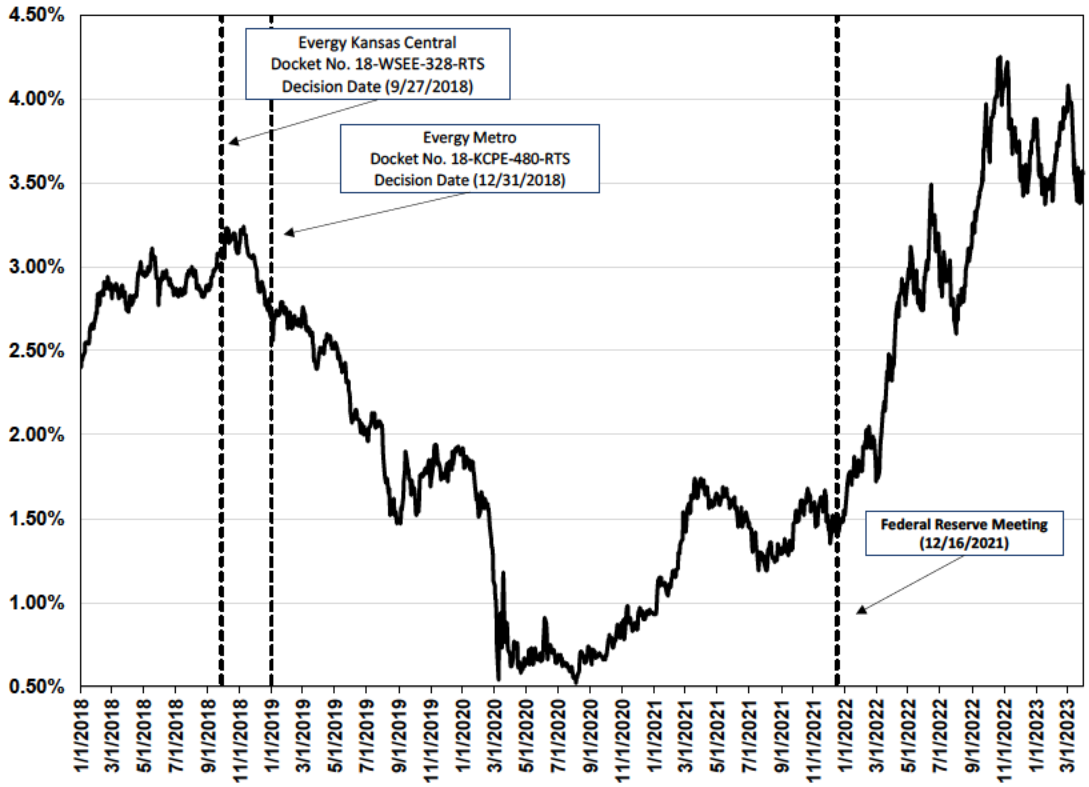
Figure 3: 10-Year Treasury Bond Yield, February 2018 through March 2023[13]



Q: What have equity analysts said about long-term government bond yields?

A: Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated through at least the end of 2023. According to the most recent *Blue Chip Financial Forecasts* report, the consensus estimate of the average yield on the 10-year Treasury bond is approximately 3.50 percent through the first quarter of 2024.[14]

[13] S&P Capital IQ Pro.

[14] *Blue Chip Financial Forecasts*, Vol. 42, No. 4, March 31, 2023.

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Q: Do recent changes in Gross Domestic Product ("GDP") affect the current outlook for inflation and interest rates?

A: No. While FOMC participants have recently reduced their projections for economic activity for real GDP growth to 0.5 percent in 2023,[15] which is well below the median estimate for the longer-run normal GDP growth rate, the Fed has highlighted that the labor market continues to be extremely tight, and in fact, the unemployment rate reached 3.4 percent in January 2023, the lowest it has been in over 50 years.[16] Therefore, with a tight labor market and persistently high inflation, the Fed has indicated its need to continue a restrictive monetary policy to moderate demand to better align it with supply.[17]

Q: How have market conditions changed since the last rate cases for the Companies?

A: As shown in Figure 4 when the Commission authorized an ROE of 9.30 percent in EKC's and EKM's 2018 rate proceedings, interest rates (as measured by the 30-year Treasury bond yield) were in the range of 3.09 percent to 3.18 percent and inflation was in the range of 1.92 percent to 2.36 percent. Further, the average beta for the proxy group companies was 0.59, which was substantially below the historical average. However, since those last rate proceedings of the Companies, long-term interest rates have increased over 60 basis points, and as discussed, inflation is also substantially higher. The proxy group average beta has also increased to 0.87, which is above the ten-year historical average of 0.74.

[15] FOMC. Summary of Economic Projections. December 14, 2022.

[16] Mutikani, Lucia. "U.S. reports blowout job growth; unemployment lowest since 1969." Reuters, February 3, 2023.

[17] Transcript. Chair Powell, Press Conference, February 1, 2023.

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Figure 4: Change in Market Conditions Since the Last Rate Cases of EKM and EKC[18]

Docket	Decision Date	Target Federal Funds Rate	30-Day Average Of 30-Year Treasury Bond Yield	Inflation Rate	Proxy Group Beta	Authorized ROE
18-WSEE-328-RTS (EK)	9/27/2018	2.00%-2.50%%	3.09%	2.36%	0.59	9.30%
18-KCPE-480-RTS (EM)	12/31/2018	2.25%-2.50%	3.18%	1.92%	0.59	9.30%
Current	3/31/2023	4.75%-5.00%%	3.81%	5.99%	0.87	

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

Q: Are utility share prices correlated to changes in the yields on long-term government bonds?

A: Yes. Interest rates and utility share prices are inversely correlated, which means that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships

[18] St. Louis Federal Reserve Bank; Bureau of Labor Statistics.

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with bond yields (*i.e.*, increases in bond yields resulted in the decline of utility share prices).[19]

Q: How do equity analysts expect the utilities sector to perform in an increasing interest rate environment?

A. Equity analysts project that utilities will underperform the broader market given high inflation and the recent increases in interest rates. Fidelity classifies the utility sector as underweight,[20] and Keybanc Capital Markets analyst Sophie Karp recently noted she had a negative view of the sector in 2023 and expects a decline in the relative valuation of the utilities sector as compared to the S&P 500:

> The utility sector's relative outperformance came on the back of the pre-recessionary environment in the U.S. in 2022, analyst Karp said. She noted that the sector now traded at a 2.8 times premium to the S&P 500 Index, which is relatively wide by historical standards.
>
> *She said the utility sector is relatively overvalued and will see a mean reversion in 2023*, adding that the last time such a premium over the S&P 500 Index happened was in 2004.
>
> *"We are therefore negative on the sector overall going into 2023 and our OW picks grow fewer*," Karp said,
>
> *There has been a surprising deterioration of the regulatory environment across multiple jurisdictions, including the historically stronger ones*, she noted. Some regulatory developments, according to the analyst, are driven by the regulator's desire to moderate the impact on customer bills. "Given that power and commodity prices remain elevated, we expect to continue seeing regulators getting 'creative' with assumptions and rate mechanisms to achieve that goal," she added.
>
> Karp said she would focus on rate affordability, as inflationary pressures will likely be a factor for the foreseeable future.

[19] Lee, Justina. "Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks." Bloomberg.com, March 11, 2021.

[20] Fidelity. "First Quarter 2023 Investment Research Update." February 8, 2023.

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> "As we turn to 2023, we believe that the sector will find it difficult to defend this relative valuation position, particularly as macro headwinds persist and begin to take a toll on utility earnings," she added.[21]

Additionally, *The Wall Street Journal* recently attributed the 14 percent decline in the S&P Utilities Index between September and October 2022 to the recent increase in long-term treasury yields:

> A big draw of utility stocks has become less attractive as interest rates have climbed. Utility stocks are known for their sizable dividends, offering investors a regular stream of income. Companies in the S&P 500 utilities sector offer a dividend yield of 3.3%, among the highest payout percentages in the index, according to FactSet.
>
> But the outsize dividends of utility stocks are no match for climbing bond yields. The yield on the benchmark 10-year Treasury note finished above 4% on Monday for a second consecutive session. Friday marked the 10-year yield's first close above the 4% level since 2008 and 11 straight weeks of gains. Treasurys are viewed as essentially risk-free if held to maturity.
>
> "The 10-year is repricing everything. I've got something that's even safer and yields even more," said Kevin Barry, chief investment officer at Summit Financial, comparing Treasurys and utility stocks.[22]

Similarly, Barron's recently noted that the decline in share prices can be attributed to the relatively high valuations and low dividend yields of utilities as compared to other asset classes such as Treasuries. [23] According to Barron's, even after the recent decline in share prices, the Utilities Select ETF was yielding 2.85 percent, which is a yield that will not "lure in buyers when the ultrasafe 10-year Treasury note yields close to 4%."[24] Therefore, Barron's currently recommends not buying utility stocks.

[21] Market Insider. "After A 'Good Run' For Utilities In 2022, Analyst Says 'Trade Is Over – For Now,' But Retains Bullish Bias On These Stocks", January 17, 2023.

[22] Miao, Hannah. "Utility Stock stumble as treasury yields climb." *The Wall Street Journal*, October 18, 2022.

[23] Sonenshine, Jacob. "Utilities Stocks Have Fallen off a Cliff. They Just Got Downgraded, Too." Barron's, October 17, 2022.

[24] *Id.*

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Q: Why do equity analysts expect the utility sector to underperform over the near-term?

A: While interest rates have increased substantially over the past year, the valuations of utilities have remained elevated and have not fully reflected the effect of the recent increase in interest rates. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds (*i.e.*, the "yield spread"). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds. As shown in Figure 5, the yield spread as of January 31, 2023 was negative 0.49 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. Furthermore, the current negative yield spread is well below the long-term average yield spread since 2010 of 1.34 percent. Given that the yield spread is currently well below the long-term average, as well as the expectation that interest rates will remain relatively high through at least through the next year, it is reasonable to conclude that the utility sector will most likely underperform over the near-term. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate back into government bonds, particularly as the yields on long-term government bonds remain elevated, thus resulting in a decrease in the share prices of utilities.

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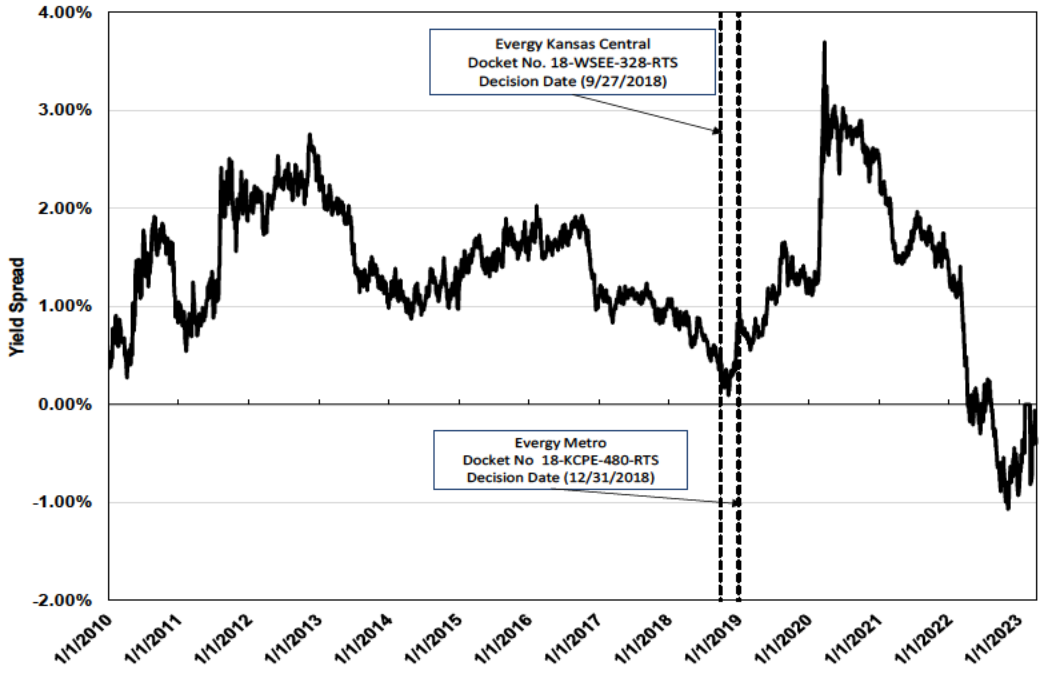
Figure 5: Spread between the S&P Utilities Index Dividend Yield and the 10-year Treasury bond Yield, January 2010 – March 2023[25]



Q. What is the significance of the inverse relationship between interest rates and utility share prices in the current market?

A.: If interest rates remain relatively high as expected, then the share prices of utilities, which have been strong in 2022 relative to the market, would be expected to decline. If the prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices to calculate the dividend yield, is likely to understate the dividend yield and thus the cost of equity.

[25] S&P Capital IQ Pro and Bloomberg Professional.

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E. Conclusion

Q: What are your conclusions regarding the effect of current market conditions on the cost of equity for the Companies?

A: Through 2023, investors expect long-term interest rates to remain relatively high in response to continued elevated levels of inflation and the Federal Reserve's normalization of monetary policy. Because the share prices of utilities are inversely correlated to interest rates, and government bond yields are already substantially greater than utility stock dividend yields, the share prices of utilities will likely decline, which is the reason a number of equity analysts have classified the utility sector as either underperform or underweight. The expected underperformance of utilities means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. Therefore, this expected change in market conditions supports consideration of the higher end of the range of cost of equity results produced by the DCF models. Moreover, prospective market conditions warrant consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which may better reflect expected market conditions.

VI. RECENTLY AUTHORIZED ROEs

Q: Have recently authorized ROEs been considered as an important data point in setting the ROE in rate proceedings in Kansas?

A: Yes. In the Evergy Companies' 2018 rate proceeding Staff considered the results from major rate case decisions for the six-month period prior to the preparation of his direct testimony.

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Q: Are recent authorized ROEs a useful indicator of investor expectations?

A: Yes, but it is important to consider the ROE and the relative market conditions at the time that the decision was in place. As discussed in section V of my Direct Testimony, interest rates increased significantly throughout 2022, affecting the cost of equity. Therefore, while it is reasonable to use recently authorized ROEs over a very recent historical period, that is consistent with current market conditions, it would not be appropriate to review historical ROEs that were authorized under different market conditions.

Q: Have you conducted such an analysis?

Yes. Figure 6 below summarizes the recently authorized ROEs in fully litigated vertically integrated electric utility rate proceedings in the fourth quarter of 2022 and the first quarter of 2023. As shown in this figure, the average authorized ROE for the fourth quarter of 2022 was 9.87 percent and the average as of the first quarter of 2023 was 9.72 percent.

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Figure 6: Recently Authorized ROEs for Vertically Integrated Electric Utilities

Company	*Parent Company Ticker*	*Docket*	*Date*	*Return on Equity (%)*
Kingsport Power Company	AEP	D-21-00107	10/25/2022	10.00%
Pacific Gas and Electric Co.	PCG	A-21-08-015	11/3/2022	10.25%
Southern California Edison Co.	EIX	A-21-08-013	11/3/2022	10.30%
San Diego Gas & Electric Co.	SRE	A-21-08-014 (Elec)	11/3/2022	10.20%
DTE Electric Co.	DTE	C-U-20836	11/18/2022	9.90%
Pacific Gas and Electric Co.	PCG	A-22-04-008	12/15/2022	10.00%
San Diego Gas & Electric Co.	SRE	A-22-04-012	12/15/2022	9.95%
Southern California Edison Co.	EIX	A-22-04-009	12/15/2022	10.05%
Georgia Power Co.	SO	D-44280	12/20/2022	10.50%
Sierra Pacific Power Co.	BRK.A	D-22-06014	12/27/2022	9.56%
Empire District Electric Co.	AQN	Ca-PUD202100163	12/29/2022	9.30%
PacifiCorp	BRK.A	D-UE-399	12/16/2022	9.50%
Puget Sound Energy Inc.		D-UE-220066	12/22/2022	9.40%
Wisconsin Electric Power Co.	WEC	D-5-UR-110 (WEP-Elec)	12/29/2022	9.80%
Wisconsin Public Service Corp.	WEC	D-6690-UR-127 (Elec)	12/22/2022	9.80%
Consumers Energy Co.	CMS	C-U-21224	1/19/2023	9.90%
Minnesota Power Entrprs Inc.	ALE	D-E-015/GR-21-335	1/23/2023	9.65%
Cheyenne Light Fuel Power Co.	BKH	D-20003-214-ER-22	1/26/2023	9.75%
Southwestern Electric Power Co	AEP	D-U-35441	2/17/2023	9.50%
Duke Energy Progress LLC	DUK	D-2022-254-E	2/9/2023	9.60%
Upper Peninsula Power Co.		C-U-21286	3/24/2023	9.90%
Q4 2022 Average				9.87%
Q1 2023 Average				9.72%

VII. PROXY GROUP SELECTION

Q: Please provide a summary profile of the Evergy Companies.

A: Evergy Metro, Inc., of which EKM is a part, and EKC are wholly-owned subsidiaries of Evergy. EKM is a regulated electric utility that provides generation, transmission and distribution of electricity to approximately 571,500 customers in eastern Kansas and

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western Missouri.[26] As of December 31, 2022, EKM's net utility electric plant in Kansas was approximately $3.043 billion.[27] EKM currently has an investment-grade long term rating from S&P of A (Outlook: Negative) and from Moody's of Baa1 (Outlook: Stable).[28] EKC is a regulated electric utility that provides generation, transmission and distribution of electricity to approximately 730,800 customers in central and eastern Kansas.[29] As of December 31, 2022, EKC's net utility electric plant in Kansas was approximately $6.793 billion.[30] EKC currently has an investment-grade long-term rating from S&P of A- (Outlook: Negative) and from Moody's of Baa1 (Outlook: Stable).[31] The Companies' parent, Evergy, cumulatively serves approximately 1,640,800 customers in Kansas and Missouri, with EKM and EKC comprising approximately 60% of Evergy's total customers.

Q: Why have you used a group of proxy companies to estimate the cost of equity for the Companies?

A: One of the purposes of this proceeding is to estimate the cost of equity for electric utility companies that are not publicly traded. Because the cost of equity is a market-based concept and because the Companies' operations do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that are both publicly traded and comparable to the Companies in certain fundamental business and financial respects to serve as their "proxy" in the cost of equity estimation process.

[26] Evergy, Inc. Form 10-K 2021 Annual Report, at 15.

[27] Provided by the Companies.

[28] S&P and Moody's Ratings, accessed February 7, 2023.

[29] Evergy, Inc. Form 10-K 2021 Annual Report, at 15.

[30] Provided by the Companies.

[31] S&P and Moody's Ratings accessed February 7, 2023.

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Even if the Companies' electric utility operations in Kansas did constitute the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given period of time. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The companies included in the proxy group all possess a set of operating and risk characteristics that are substantially comparable to the Companies', and thus provide a reasonable basis to derive and estimate an appropriate cost of equity for the Companies.

Q: How did you select the companies included in your proxy group?

A: I began with the group of 36 companies that *Value Line* classifies as electric utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, since companies that do not cannot be analyzed using the constant growth DCF model;
- have investment grade long-term issuer ratings from both S&P and Moody's;
- are covered by more than one utility industry analyst;
- have positive long-term earnings growth forecasts from at least two equity analysts;
- own generation assets included in rate base;
- derive at least 40 percent of sales from company-owned generation;
- derive at least 60 percent of the company's total operating income from regulated operations;
- derive at least 60 percent of the company's total regulated operating income from regulated electric operations; and
- were not party to a merger or transformative transaction during the analytical period considered.

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Q: Did you exclude any other companies from the proxy group?

A: Yes. I also excluded Hawaiian Electric Industries, Inc. ("HE") on the basis that its operations are concentrated on the islands of Hawaii, and therefore, the company faces geographic concentration risk for both its regulated and substantial unregulated operations not applicable to the other utilities considered. As HE noted in the company's 2021 Form10-K:

> The Company is subject to the risks associated with the geographic concentration of its businesses and current lack of interconnections that could result in service interruptions at the Utilities or higher default rates on loans held by ASB [American Savings Bank].[32]

The increased risk of service interruptions resulting from HE's geographic location that could result in revenue loss and increased costs is a risk unique to HE and would not apply to utilities located on the U.S. mainland. Furthermore, HE's unregulated operations, which represent approximately 33 percent of the company's operation income in 2021 are concentrated in the banking sector through the ownership of American Savings Bank ("ASB").[33] ASB also only operates on Hawaii; thus, all of the company's consumer and commercial loans are to customers on Hawaii. If Hawaii were to face an adverse economic or political event, ASB could face severe financial effects given the company's geographic concentration in Hawaii.[34] As a result, I have excluded HE from my proxy group considering HE's unique geographical risks.

[32] Hawaii Electric Industries, Inc., 2021 Form 10-K, at 23.

[33] *Id*., at 86.

[34] *Id*., at 20.

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Q: What is the composition of your proxy group?

A: The screening criteria discussed above is shown in **Exhibit AEB-2** and results in a proxy group consisting of the companies shown in Figure 7 below:

Figure 7: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Dominion Resources, Inc.	D
Duke Energy Corporation	DUK
Entergy Corporation	ETR
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Otter Tail Corporation	OTTR
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

Q: Why is it appropriate to recognize the risks of owning generation in developing the proxy group?

A: As discussed, EKM and EKC are vertically-integrated electric utilities, and the overall purpose of developing a set of screening criteria is to select a proxy group of companies that align with the financial and operational characteristics of the Companies and that

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investors would view as comparable to the Companies. Thus, I have applied a screening criterion to remove companies that do not own substantial amounts of generation and therefore, may not be as comparable to the Companies. According to Moody's, generation ownership causes vertically-integrated electric utilities to have higher business risk than either electric transmission and distribution companies, or natural gas distribution or transportation companies. For example, Moody's states that:

> Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.[35]

Q: Is there additional evidence that vertically-integrated electric utilities have different risk profiles than transmission and distribution-only utilities?

A: Yes. Many states across the U.S. have either set goals or mandated standards for increasing the amount of renewable generation and decreasing carbon emissions. Furthermore, many utilities across the U.S. have voluntarily developed clean energy commitments with long-term goals such as net-zero emissions and 100 percent renewable generation. Thus, vertically-integrated electric utilities will be transforming their generation fleets over the next few decades to achieve these goals and mandates. For example, Evergy has a goal to achieve net-zero carbon emissions by 2045 with an interim goal of 70 percent reduction in carbon emissions from 2005 levels by 2030.[36] As I discuss in more detail later herein,

[35] Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities, April 2022, at 21.

[36] Evergy, Inc. Form 10-K 2021 Annual Report, at 10.

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Evergy plans to achieve these goals by retiring approximately 1,900 MW of fossil fuel generation (*i.e.*, fueled by coal, oil, and natural gas) and adding approximately 3,500 MW of renewable generation (*i.e.*, solar and wind) over the next ten years.

Thus, the long-term transition of the generation fleets of vertically-integrated electric utilities will require significant investment in renewable generation as well as the retirement of many coal- and natural gas-fired generation assets. While transmission and distribution-only ("T&D") utilities will also need to invest in their transmission and distribution systems to facilitate the transition to clean energy generation, T&D utilities will not face the risk associated with fossil fuel generation retirements and the need to build new renewable generation. Therefore, the risks confronted by a vertically-integrated electric utility are quite different from the risks confronted by a T&D utility over the near and long term. As a result, I have applied a generation screening criterion to ensure that a significant portion of the total sales of each of the proxy group companies are supplied with power from generation assets that they own, which is similar to EKM and EKC.

VIII. COST OF EQUITY ESTIMATION

Q: Please briefly discuss the ROE in the context of the regulated rate of return.

A: The overall rate of return for a regulated utility is the weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. The ROE is the cost of common equity capital in the utility's capital structure for ratemaking purposes. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

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Q: How is the required cost of equity determined?

A: The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company in the context of the proxy group, in particular.

Q: What methods did you use to determine your recommended ROE in this proceeding?

A: I considered the results of the constant growth DCF model, the CAPM, the ECAPM, and the Bond Yield Plus Risk Premium analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q: Is it important to use more than one analytical approach to estimate the cost of equity?

A: Yes. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of

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equity. For example, Copeland, Koller, and Murrin[37] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[38] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q: Do current market conditions support the use of more than one analytical approach?

A: Yes. As I discussed above, interest rates have increased substantially over the past year and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. The benefit of using multiple models is that each model relies on different assumptions, certain of which may better reflect current and projected market conditions at different times. As discussed previously, the CAPM, ECAPM, and Bond Yield Plus Risk Premium analysis offer some balance through the use of projected interest rates since the effect of changes in interest rates, particularly the recent increase in interest rates, may not be captured as well in the DCF model at this time. Therefore, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Companies' rates will be in effect.

Q: Has the Commission previously recognized that it is important to consider the results of multiple cost of equity models?

A: Yes. In its order in Docket No. 10-KCPE-415-RTS, the Commission determined the authorized ROE for EKM based on both the DCF and the CAPM analyses presented by the witnesses in the proceeding. Specifically, the Commission noted that:

> The last main capital issue raises the question of whether CAPM is appropriate to include in setting the ROE. For us, this is not a difficult question, and we find that in this case, under the economic conditions that exist and under which all parties have labored, CAPM should be included. We also conclude, as a

[37] Copeland, Tom, Tim Koller and Jack Murrin. Valuation: Measuring and Managing the Value of Companies. New York, McKinsey & Company, Inc., 3rd Ed., 2000, at 214.

[38] Brigham, Eugene and Louis Gapenski. Financial Management: Theory and Practice. Orlando, Dryden Press, 1994, at 341.

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> matter of law, that we are afforded broad discretion in setting the ROE, and interpret that discretion to extend beyond a rigid formulaic approach. Therefore, after reviewing the evidence presented by all three parties on the CAPM question, we are most persuaded by the testimony offered by Crane and Gatewood. Using both CAPM and DCF generates an analysis that encompasses the current economic climate.[39]

Furthermore, the Commission has noted in subsequent orders that it has relied on the evidence provided by each of the ROE witnesses in the case in the determination of the ROE.[40]

A. Constant Growth DCF Model

Q: Please describe the DCF approach.

A: The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required COE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

[39] Kansas Corporation Commission, Docket No. 10-KCPE-415-RTS, Order: 1) Addressing Prudence; 2) Approving Application, in Part; & 3) Ruling on Pending Requests, November 22, 2010, at 43.

[40] *See, e.g.,* Kansas Corporation Commission, Docket No. 12-KCPE-764-RTS, Order, December 13, 2012, at 11; Kansas Corporation Commission, Docket No. 15-KCPE-116-RTS, Order, September 10, 2015, at 16; and Kansas Corporation Commission, Docket No. 19-ATMG-525-RTS, Order, February 24, 2020, at 8.

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Equation [2] is often referred to as the constant growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q: What assumptions are required for the constant growth DCF model?

A: The constant growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are not objectively valid, considered judgment and/or specific adjustments should be applied to the results.

Q: What market data do you use to calculate the dividend yield in your constant growth DCF model?

A: The dividend yield in my constant growth DCF model is based on the proxy group companies' current annualized dividend and average closing stock prices over the most recent 30, 90, and 180 trading days ended March 31, 2023.

Q: Why did you use three averaging periods for stock prices?

A: I use an average of recent trading days to calculate the term P_0 in the DCF model to reflect current market data while also ensuring that the result of the model is not skewed by anomalous events that may affect stock prices on any given trading day.

Q: Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A: Yes. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected

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dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q: Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A: In its constant growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume that the payout ratio remains constant and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to consider a variety of sources in arriving at a single projected long-term earnings growth rate for the constant growth DCF model.

Q: Which sources of long-term earnings growth rates did you use in your DCF analysis?

A: I incorporate three sources of long-term earnings per share ("EPS") growth rates: (1) Zacks Investment Research; (2) Yahoo! Finance; and (3) *Value Line*.

Q: Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A: Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends.

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Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q: Have EPS growth rates been relied upon in the DCF in prior Kansas rate proceedings?

A: Yes. Staff Witness Gatewood relied on EPS growth rates in his DCF analysis in the Companies' 2018 rate case proceeding.[41]

Q: How did you calculate the range of results for the constant growth DCF model?

A: I calculated a low-end result for my DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the Zacks, Yahoo Finance, and *Value Line* projected earnings growth rates) for each of the proxy group companies. I used a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculated results using the average growth rate from all three sources for each proxy group company.

Q: What are the results of your constant growth DCF analyses?

A: Figure 8 (see also **Exhibit AEB-3**) summarizes the results of my DCF analysis. As shown in Figure 8, the mean and median DCF results using the average growth rates range from 9.50 percent to 9.85 percent, and the mean and median results using the maximum growth rates range from 9.98 percent to 10.84 percent. While I also summarize the DCF results using the minimum growth rates, given the expected underperformance of utility stocks going forward and thus the likelihood that the DCF model is understating the cost of equity, I do not believe it is appropriate to consider these DCF results at this time.

[41] Docket No. 18-KCPE- 480-RTS, Direct Testimony of Adam Gatewood at 36.

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Figure 8: Summary of Constant Growth DCF Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.65%	9.85%	10.84%
90-Day Avg. Stock Price	8.58%	9.78%	10.77%
180-Day Avg. Stock Price	8.59%	9.79%	10.78%
Average	8.61%	9.80%	10.80%
Median Results:			
30-Day Avg. Stock Price	9.20%	9.62%	10.07%
90-Day Avg. Stock Price	9.09%	9.56%	10.01%
180-Day Avg. Stock Price	9.04%	9.50%	9.98%
Average	9.11%	9.56%	10.02%

Q: Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of high inflation and increased interest rates?

A: Yes. For example, in its May 2022 decision establishing the cost of equity for Aqua Pennsylvania, Inc., the Pennsylvania Public Utility Commission concluded that the current capital market conditions of high inflation and increased interest rates has resulted in the DCF model understating the utility cost of equity, and that weight should be placed on risk premium models, such as the CAPM, in the determination of the ROE:

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a

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> check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.[42]
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[43]

Q: Did you rely on the use of a two-stage DCF model?

A: No, I did not. Utilities are considered a mature industry, as such it is not necessary to adjust the growth rate to reflect a longer-term steady state. Therefore, I have relied on the constant growth version of the DCF model.

Q: Are you aware that the Federal Energy Regulatory Commission ("FERC") relies on a two-stage DCF model that averages earnings per share growth rates with nominal GDP growth?

A: Yes, I am. However, it is important to note that in Opinion No. 569-A, the FERC recognized that the growth rate of electric utilities have declined and are now closer to the current GDP growth rate projections than those from the 1990s when the FERC adopted a two-step DCF methodology that weighted GDP growth as one-third of the growth rate in

[42] Pennsylvania Public Utility Commission, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order, May 12, 2022, pp. 154–155.

[43] *Id*., pp. 177–178.

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the DCF. As a result, the FERC reduced the weighting on GDP growth to 20 percent of the total growth rate in that proceeding. This change in the emphasis on GDP growth was affirmed in FERC Opinion 575.[44]

Q: What are your conclusions about the results of the DCF models?

A: As discussed previously, one primary assumption of the DCF models is a constant price-to-earnings ratio, and that assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates remain elevated and yields on long-term government bonds exceed utility dividend yields, it is important to consider the results of the DCF models with caution. Therefore, while I have given weight to the results of the constant growth DCF model, my recommendation also gives weight to the results of other cost of equity estimation models.

B. CAPM Analysis

Q: Please briefly describe the CAPM.

A: The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

[44] FERC Opinion No. 569-A 171 FERC 61,154 at PP 57-58. See also FERC Opinion No 575 at P 131.

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The CAPM is defined by four components:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term $(r_m - r^f)$ represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, Variance (r_m)) is a measure of the uncertainty of the general market, and the Covariance between the return on a specific security and the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, beta represents the risk of the security relative to the general market.

Q: What risk-free rate do you use in your CAPM analysis?

A: I rely on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds, which is 3.81 percent;[45] (2) the average projected 30-year Treasury bond yield for the second quarter of 2023 through the second quarter of 2024,

[45] Bloomberg Professional as of March 31, 2023.

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which is 3.78 percent;[46] and (3) the average projected 30-year Treasury bond yield for 2024 through 2028, which is 3.90 percent.[47]

Q: What beta coefficients do you use in your CAPM analysis?

A: As shown in **Exhibit AEB-4**, I use the beta coefficients for the proxy group companies as reported by Bloomberg and *Value Line*. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The beta coefficients reported by *Value Line* are calculated using five years of weekly returns relative to the NYSE Composite Index. Additionally, as shown in **Exhibit AEB-5**, I consider another CAPM analysis that relies on the long-term average beta coefficient for the companies in my proxy group, which is calculated as an average of the *Value Line* beta coefficients for the companies in my proxy group from 2013 through 2022.

Q: How do you estimate the market risk premium in the CAPM?

A: I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Attachment AEB-6, the expected market return is calculated using the constant growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.76 percent and a weighted long-term growth rate of 10.26 percent, the estimated required market return for the S&P 500 Index as of March 31, 2023, is 12.11 percent. Based on the three risk-free rates considered, the market risk premium ranges from 8.21 percent to 8.33 percent.

[46] *Blue Chip Financial Forecasts*, Vol. 42, No. 4, March 31, 2023, at 2.
[47] *Blue Chip Financial Forecasts*, Vol. 41, No. 12, December 2, 2022, at 14.

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Q: You calculate the market risk premium as the difference between the market return and the income return on government bonds. Is it appropriate to use the income return on government bonds as opposed to the total return on government bonds?

A: Yes. Morningstar (now Kroll), one of the publishers of the historical market risk premium data, discussed this in its publication *Stocks, Bonds, Bills and Inflation,* which has been relied upon by cost of capital witnesses in regulatory proceedings for decades. As noted by Morningstar:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in react to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[48]

Q: How does the current expected market return of 12.50 percent compare to observed historical market returns?

A: As shown in Figure 9, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.11 percent is not unreasonable. As shown, in 50 out of the past 96 years (or roughly 52 percent of observations), the realized equity market return was 12.11 percent or greater.

[48] Morningstar, Inc. 2010, Ibbotson SBBI 2010 Valuation Yearbook at 55.

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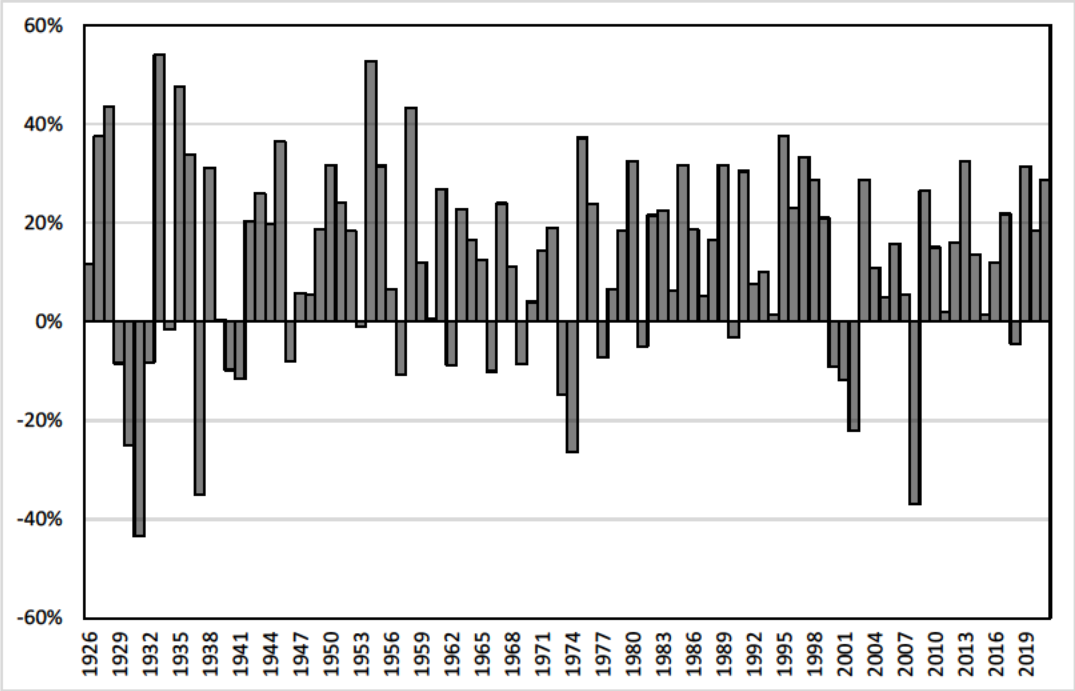
Figure 9: Realized U.S. Equity Market Returns (1926-2021)[49]



Q: Did you consider another form of the CAPM in your analysis?

A: Yes. I have also considered the results of an ECAPM analysis in estimating the cost of equity for the Companies.[50] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

[49] Depicts total annual returns on large company stocks, as reported in the 2022 *Kroll* SBBI Yearbook.

[50] *See, e.g.*, Morin, Roger A. New Regulatory Finance. Public Utilities Reports, Inc., 2006, at 189.

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$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

Where:

k_e = the required market ROE

β = adjusted beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

In essence, the ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM; rather, it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.[51]

As with the CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current Bloomberg, current *Value Line*, and long-term *Value Line* beta coefficients.

Q: What are the results of your CAPM analyses?

A: As shown in Figure 10 (see also **Exhibit AEB-4**), my traditional CAPM analysis produces a range of returns from 9.96 percent to 11.06 percent. The ECAPM analysis results range from 10.50 percent to 11.32 percent.

[51] *Id*., at 191.

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Figure 10: CAPM and ECAPM Results

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.05%	11.05%	11.06%
Current Bloomberg Beta	10.49%	10.48%	10.50%
Long-term Avg. *Value Line* Beta	9.97%	9.96%	9.99%
ECAPM:			
Current *Value Line* Beta	11.31%	11.31%	11.32%
Current Bloomberg Beta	10.89%	10.89%	10.91%
Long-term Avg. *Value Line* Beta	10.50%	10.50%	10.52%

C. Bond Yield Plus Risk Premium Analysis

Q: Please describe the Bond Yield Plus Risk Premium approach.

A: In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Thus, risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I use actual authorized returns for electric distribution companies as the historical measure of the cost of equity to determine the risk premium.

Q: Are there other considerations that should be addressed in conducting this analysis?

A: Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice

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versa). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs for electric utilities serve as the measure of required equity returns and the yield on the long-term Treasury bond is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[52]

Q: Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A: Yes. Investors are aware of authorized ROEs in other jurisdictions, and they consider those authorizations as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors in the current interest rate environment.

Q: What did your Bond Yield Plus Risk Premium analysis reveal?

A: As shown in Figure 11 below, from 1992 through March 31, 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

[52] *See e.g.*, Berry, S. Keith. "Interest Rate Risk and Utility Risk Premia during 1982-93." Managerial and Decision Economics, Vol. 19, No. 2, March, 1998 (the author used a similar methodology, including using authorized ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates). *See also* Harris, Robert S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management*, Spring 1986, at 66.

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$$RP = a + bT \qquad [6]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year Treasury bonds)

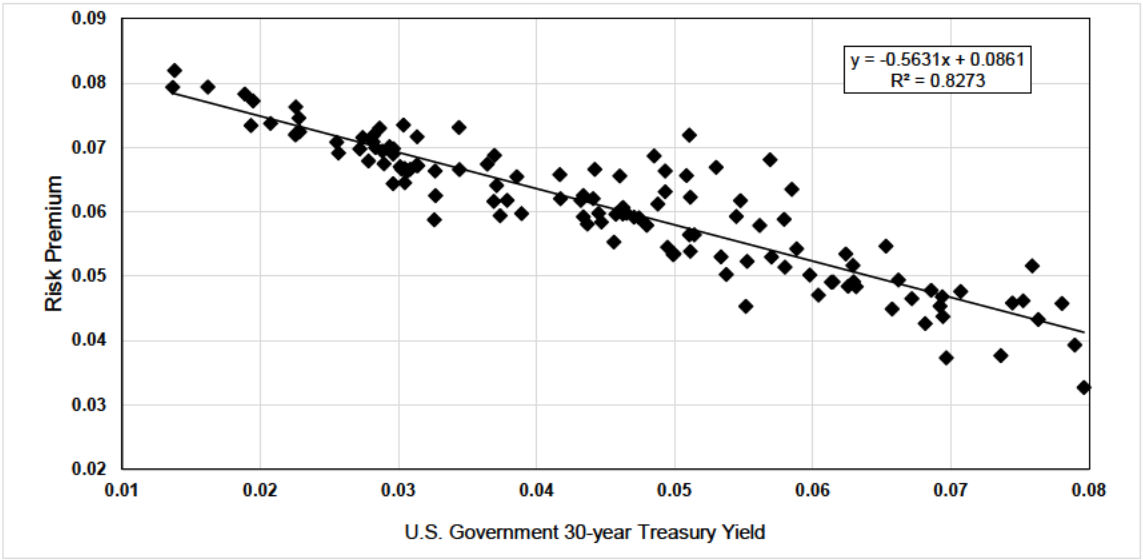
a = intercept term

b = slope term

T = 30-year Treasury bond yield

Data regarding authorized ROEs were derived from all electric distribution rate cases from 1992 through March 2023 as reported by Regulatory Research Associates ("RRA").[53] This equation's coefficients were statistically significant at the 99.00 percent level.

Figure 11: Risk Premium Regression Analysis



As shown on **Exhibit AEB-7**, based on the current 30-day average of the 30-year U.S. Treasury bond yield, the risk premium would be 6.47 percent, resulting in an estimated cost of equity of 10.27 percent. Based on the near-term (Q2 2023– Q2 2024) projections

[53] This analysis began with over 1,400 cases and was screened to eliminate limited issue rider cases, transmission-only cases, and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data from over 700 cases.

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of the 30-year U.S. Treasury bond yield, the risk premium would be 6.43 percent, resulting in an estimated cost of equity of 10.31 percent. Based on longer-term (2024-2028) projections of the 30-year U.S. Treasury bond yield, the risk premium would be 6.41 percent, resulting in an estimated cost of equity of 10.31 percent.

Q: How did the results of the Bond Yield Risk Premium inform your recommended ROE for the Companies?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for the Companies. As noted above, investors consider the authorized ROE determination by a regulator when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

IX. REGULATORY AND BUSINESS RISKS

Q: Taken alone, do the results from the cost of equity estimation models for the proxy group provide an appropriate estimate of the cost of equity for the Companies?

A: No. These analyses provide only a range of the appropriate estimate of the Companies' cost of equity. There are several additional factors that must be taken into consideration when determining where the Companies' cost of equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Companies' risk profile.

A. Capital Expenditures

Q: Please summarize the Companies' capital expenditure requirements.

A; As of December 31, 2022, EKM had net utility plant of approximately $3.270 billion, and EKM currently projects capital expenditures for 2023 through 2027 of approximately

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$1.528 billion.[54] Therefore, EKM's projected capital expenditures represent approximately 46.73 percent of its net utility plant as of December 31, 2022. Over the same time period, EKC had net utility plant of $9.514 billion and capital expenditures for 2023 through 2027 of approximately $6.077 billion.[55] Therefore, EKC's projected capital expenditures represent approximately 63.87 percent of their net utility plant as of December 31, 2022.

Q: How is the Companies' risk profile affected by its substantial capital expenditure requirements?

A: As with any utility faced with substantial capital expenditure requirements, the Companies' risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under-recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q: Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A: Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for a significant amount of capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable

[54] Data provided by the Companies.

[55] Data provided by the Companies.

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> for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[56]

Therefore, to the extent the Companies' rates do not continue to permit the recovery of its capital investments on a regular basis, the Companies would face increased recovery risk and thus increased pressure on its credit metrics.

Q: How do the Companies' capital expenditure requirements compare to those of the proxy group companies?

A: As shown on **Exhibit AEB-8**, I calculated the ratio of expected capital expenditures to net utility plant for each of the companies and each of the companies in the proxy group by dividing each company's projected capital expenditures for 2023-2027 by its total net utility plant as of December 31, 2022. As shown therein, EKM's ratio of capital expenditures as a percentage of net utility plant is slightly below the median for the proxy group. EKC's capital expenditures are at the high end of the range as compared with the proxy group.

B. Regulatory Risk

Q: How does the regulatory environment affect investors' risk assessments?

A: The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital

[56] S&P Global Ratings. "Assessing U.S. Investor-Owned Utility Regulatory Environments." August 10, 2016, at 7.

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intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and doing so balances the long-term interests of investors and customers. To achieve this balance, the Companies must be able to finance their operations assuming a reasonable opportunity to earn an appropriate return on invested capital to maintain an acceptable financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally-generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

In addition, equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows

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Q: How do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Both Moody's and S&P consider the overall regulatory framework in establishing credit ratings. Specifically, Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[57]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[58] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[59]

Q: How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A: The regulatory environment can significantly affect both access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted

[57] Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities. June 23, 2017, at 4.
[58] Standard & Poor's Global Ratings. Ratings Direct. U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others. June 25, 2018, at 2.
[59] *Id*., at 1.

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by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[60] Moody's has further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[61]

Q: Have you conducted any analysis of the risk associated with the regulatory framework in Kansas relative to the jurisdictions in which the utility operating subsidiaries of the companies in your proxy group operate?

A: Yes. I have evaluated the regulatory framework in Kansas on three factors that are important in terms of providing a regulated utility a reasonable opportunity to earn its authorized ROE: (1) test year convention (*i.e.*, forecast vs. historical); (2) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk and stabilize revenue; and (3) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in **Exhibit AEB-9** and are summarized as follows:

Test Year Convention: The Companies currently use a historical test year, and approximately 51 percent of the utility operating subsidiaries of the companies in the proxy group use fully or partially forecasted test years.

Revenue Stabilization / Volumetric Risk: Neither Evergy Central nor Evergy Metro currently have protection against volumetric risk in Kansas. In comparison,

[60] Moody's Investors Service. Rating Methodology: Regulated Electric and Gas Utilities. June 23, 2017, at 6.
[61] *Id*.

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approximately 57 percent of the operating utility subsidiaries of the proxy group companies have some form of revenue stabilization.

Capital Cost Recovery: Evergy Central and Evergy Metro have a rate rider that provides for the recovery of transmission capital costs in Kansas. While this mechanism helps reduce regulatory lag, this mechanism only addresses 35 percent of EKC's capital expenditures and 15 percent of EKM's capital expenditures. Approximately 79 percent of the operating utility companies of the proxy group have some form of capital cost recovery mechanism in place that allows them to recover capital investments that are placed into service between rate cases.

Q: Have you developed any additional analyses to evaluate the regulatory environment in Kansas as compared to the jurisdictions in which the companies in your proxy group operate?

A: Yes. I have conducted two additional analyses to compare the regulatory framework of Kansas to the jurisdictions in which the utility operating subsidiaries of the proxy group operate. Specifically, I considered two different rankings: (1) the Regulatory Research Associates ("RRA") ranking of regulatory jurisdictions, which is presented in **Exhibit AEB-9**; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions, which is presented in **Exhibit AEB-10.**

Q: Please explain how you used the RRA ratings to compare the regulatory jurisdictions of the utility operating subsidiaries of the proxy companies relative to the Companies?

A: RRA assigns a ranking for each regulatory jurisdiction between "Above Average/1" to "Below Average/3," with nine total rankings between these categories. I applied a similar numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest

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ranking ("1") and "Below Average/3" assigned the lowest ranking ("9"). As shown on **Exhibit AEB-10**, the Companies' jurisdictional ranking is "7" or "Below Average / 1", which is over two notches below the proxy group's average numeric ranking of "4.55" from RRA, which is between "Average / 1" and "Average / 2."

Q: How did you conduct your analysis of the S&P credit supportiveness?

A For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Credit Supportive" to "Most Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate relative to the Companies' regulatory jurisdiction is similar to the analysis of the RRA overall regulatory ranking just discussed. Specifically, I assign a numerical ranking to each of S&P's categories, from Most Credit Supportive ("1") to Credit Supportive ("5"). As shown in **Exhibit AEB-11**, the proxy group average ranking is 2.41, which would be classified between "Very Credit Supportive" and "Highly Credit Supportive," while the Companies' rank is slightly higher at "Highly Credit Supportive" ("2"), which suggests that investors perceive regulation for the Companies as consistent with, albeit slightly above average, relative to the proxy group.

Q: How do the returns that have been authorized in Kansas compare with the authorized returns in other jurisdictions?

A: While nearly all the result of settlement agreements approved by the Commission, as shown in Figure 12, the authorized returns for vertically-integrated electric utilities in Kansas have been below the average authorized ROEs for vertically-integrated electric utilities across the United States. This can pose a problem because, as noted previously, utility subsidiaries must compete for discretionary capital within their own corporate

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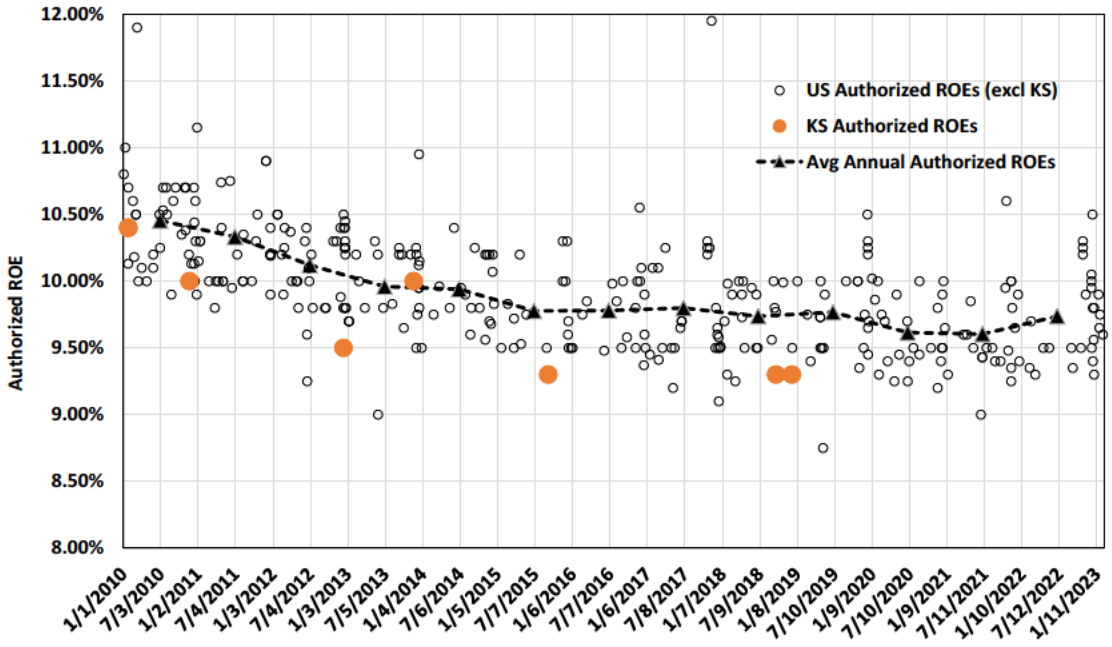
structures, which must in turn compete for capital with other utilities and businesses. Placing the Companies at the low end of authorized ROEs outside of Kansas over the longer term could negatively affect the Companies' access to discretionary capital.

Figure 12: Comparison of Kansas and US Authorized ROEs for Vertically-Integrated Electric Utilities



Q: How are credit rating agencies currently viewing the utility sector?

A: Credit rating agencies have indicated that the industry overall has increased risk, has responded with close scrutiny of the financial coverage ratios of the sector, and has a negative outlook on the industry overall for 2023. Therefore, it is critically important to consider these factors and to recognize that the investor-required cost of equity would be higher today than at the time of Commission decisions in the recent past. As previously,

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current market conditions demonstrate greater risk than at the time the Commission authorized returns in the recent past.

Q: What is your conclusion regarding the regulatory framework in Kansas as compared with the jurisdictions in which the proxy group companies operate?

A: The regulatory framework in which a regulated utility provides service is one of the most important consideration for debt and equity investors. Based on my analysis, I conclude that the regulatory risk for EKC is higher than the proxy group, and EKM is slightly above the average for the proxy group, which reflects the limited Kansas's regulatory framework has somewhat greater risk than the jurisdictions in which the utility operating subsidiaries of the proxy group companies provide service. This reflects the Companies' use of a historical test year and limited revenue stabilization and capital cost recovery between rate cases, and the RRA's ranking relative to other jurisdictions.

X. CAPITAL STRUCTURE

Q: Is the capital structure an important consideration in the determination of the appropriate ROE for the Companies?

A: Yes. It is a fundamental tenet of finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, assuming all else equal, the greater the debt ratio, the greater the risk to equity investors, and thus the greater the return required by equity investors. This is because the claim of equity holders on the cash flows of the Companies is secondary to debt holders, meaning the greater the debt service requirement, the less cash flow is available for common equity holders.

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In this proceeding, a proxy group of comparable companies is being used to determine the Companies' ROEs. The returns that are required by investors for the proxy companies take into consideration the risk related to the capitalization of those companies. Thus, to the extent that the capital structure authorized for the Companies was to deviate significantly from the range established by the proxy group used to determine the ROE, that risk difference must be reflected in the equity return.

Q: Should the choice of capital structure change the overall weighted average cost of capital?

A: No. The capital structure and the return on debt and equity are not severable and therefore must be evaluated as a set of assumptions. It is important to recognize that the changes in the capital structure will affect the cost rates of the components of the capital structure. The use of more or less leverage (debt) in the capital structure affects the overall risk profile of the company. The return on debt and equity are investors' required returns for the risk associated with the repayment of the investment (equity or debt). Debt has priority repayment over equity, and therefore has a lower overall cost. The amount of debt that is included in the capital structure can however affect the overall cost of debt. Higher leverage will likely result in higher debt costs, as the risk associated with repayment increases with the increase in the required payments on debt instruments. Further, fixed payments, all else equal, reduce key credit metrics that affect credit ratings and the cost of debt. Therefore, the cost of debt will change with the amount of debt relied upon.

The investor required return on equity will also change as the capitalization of a company changes. Equity bears the residual repayment risk; it is the last investor to be repaid in the event of bankruptcy of a company. Therefore, the greater the leverage, the more of the

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investments that have priority repayment before equity, the higher the investor-required return on the equity investment.

Q: What are the approaches that are most often considered by utility commissions when setting a regulated utility's capital structure for ratemaking purposes?

A: The approaches most often considered by regulatory commissions when setting a utility's capital structure are as follows:

- The operating company's actual (or projected) capital structure per the financial books and records of the company when such capital structure is reflective of the way the company is operated and it is generally consistent with industry norms.
- A hypothetical capital structure, especially if there are concerns that the actual per books capital structure is not reflective of the optimal capital structure for the company, and may be based on the capital structures of comparable companies (*e.g.*, set within the range of the proxy group) or determined by the regulatory commission based on other risk factors; and,
- The parent company's consolidated capital structure, which occurs most often when the operating company represents the vast majority of the parent holding company's operations, and therefore the financing for the operating company and the holding company are similar.

Q: Do the fundamental principles of regulation provide for the use of the actual capital structure?

A: Yes. The use of the operating utility's actual capital structure for ratemaking purposes is consistent with the stand-alone principle of ratemaking, which is a well-established regulatory principle providing that the rate of return (both return on equity and capital structure) for a regulated utility should be set as if the utility were seeking to attract capital in financial markets based on its own individual merits and risk profile. The stand-alone ratemaking principle states that rates should be established for each jurisdiction on an

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independent basis. Therefore, this principle leads to the use of the actual capital structure as the default capital structure, as long as that capital structure is reasonable by reference to industry standards or a proxy group of firms with comparable risk.

Q: Have any regulatory commissions specifically identified when each of these capital structures should be applied?

A: Yes. The FERC has established standards for when to use each type of capital structure. The FERC's preference is to rely on the actual capital structure of the utility, as long as that capital structure is within industry norms. If the utility does not provide its own financing, the FERC will next rely on the capital structure of the entity that finances the company, as long as that capital structure is reasonable. If the financing entity's capital structure is anomalous, when compared to the proxy group companies, or other capital structures for utilities of similar operations, the FERC may employ a hypothetical capital structure. [62]

Q. You stated that leverage affects the metrics that are reviewed by the rating agencies. Have the credit rating agencies highlighted pressures on utilities' cash flows that should be considered in setting the Company's capital structure?

A: Yes. The credit rating agencies have recently highlighted challenges that are placing pressure on the outlook for utilities and noted that they should be considered in setting the Companies' capital structures.

For example, Moody's 2023 outlook for the regulated gas and electric utilities sector was "negative" based on ongoing challenges of inflation, increasing interest rates

[62] *High Island Offshore System, L.L.C.* 110 FERC, ¶ 61,043, P134. See also *Enbridge*, 100 FERC ¶ 61,260 at P 173, *Michigan Gas Storage Co*., 87 FERC ¶ 61,038 at 61,157-61 (1999); *Transcontinental Gas Pipe Line Corp*., Opinion No. 414-A, 84 FERC ¶ 61,084 at 61,415 (Transco), reh'g denied, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998), petition for review denied, *North Carolina Utilities Commission* v. FERC, 203 F.3d 53 (D.C. Cir. 2000) (per curiam).

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and higher natural gas prices. Moody's noted that these challenges increase the pressure on customer affordability, and thus face heightened public scrutiny and the ability of utilities to promptly recover their costs. Moody's concluded that regulated utilities' financial metrics are already under pressure with little cushion, and that sustained capital spending is likely as utilities continue progress towards emissions reductions and net-zero goals. Moody's noted that the outlook could return to stable if regulatory support remains intact, natural gas prices are at a level where utilities are able to recover their fuel and purchased power costs without delay beyond 12 months, overall inflation moderates, interest rates stabilize and/or utilities' aggregate funds from operations-to-debt ratio remains between 14% to 15%.[63]

Fitch Ratings ("Fitch") also highlights similar factors as Moody's as challenging utilities' outlook for 2023, stating that the sector faces mounting cost pressures due to "elevated commodity prices, inflationary headwinds and rising interest costs," and that some offset in managing these headwinds include "higher authorized ROEs and the use of tools such as securitization of under-recovered fuel balances."[64]

Likewise, S&P continues to maintain a negative outlook for the utility industry,[65] noting that since downgrades outpaced upgrades for a third consecutive year in 2022 with a median investor-owned utility credit rating of "BBB+".[66]

[63] Moody's Investors Service, Outlook, "2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022; Moody's Investors Service, Outlook, Sector In-Depth, "Inflation, high natural gas prices complicate prospects for supportive rate increases," November 11, 2022.

[64] Fitch Ratings, "North American Utilities, Power & Gas Outlook 2023," December 7, 2022, at 1-2.

[65] S&P Global Ratings, "Regulated Utilities: Credit quality has weakened and credit risks are rising," July 14, 2022.

[66] S&P Global Ratings. Industry Top Trends, "North American Regulated Utilities: The industries outlook remains negative." January 23, 2023.

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Further, S&P expects the industry to have negative discretionary cash flow as a result of significant capital spending and consistent dividends.[67] Therefore, the utility industry will need ongoing access to capital markets to fund the capital expenditures. However, S&P notes that inflation, rising interests rates and decreasing equity prices may "hamper" consistent access to capital markets and result in additional pressure on cash flows.[68] Moreover, S&P indicates that if inflation risks persist over the near-term and customer bills increase, regulatory credit support could decrease resulting in weaker financial metrics for the industry:

> Over the past decade the industry's financial measures have weakened from a combination of rising capital spending, regulatory lag, and lower authorized return on equity (ROE). The industry's return on capital was about 6% a decade ago and today is closer to 4%. More recently, we have seen instances where not only is the authorized ROE lowered but also the equity ratio is lowered. These results have weakened the industry's financial measures, pressuring credit quality. Under our base case of moderating inflationary risks during 2023, we expect the industry's credit measures to generally remain flat. However, if inflationary risks persist, it may further pressure the customer bill, potentially decreasing the level of regulatory credit support, weakening the industry's financial performance.[69]

The credit ratings agencies' continued concerns over the negative effects of inflation and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the Companies in the context of this proceeding.

Q: What capital structures are the Companies proposing?

A: EKM is proposing a capital structure composed of 52 percent equity and 48 percent long-term debt. Similarly, EKC is proposing a capital structure composed of 52.0376 percent

[67] *Id.*
[68] *Id.*
[69] *Id.*

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equity and 47.9624 percent long-term debt. The proposed capital structures reflects the Companies' projected capital structures as of June 30, 2023.

Q: Is it appropriate that the Companies' capital structures reflect their actual capital structure as opposed to their parent company's capital structure or a hypothetical capital structure for ratemaking purposes?

A: Yes, for a number of reasons it is appropriate that the Companies' capital structures reflect their actual capital structures for ratemaking purposes.

First, as discussed in Mr. Andrews's testimony the Non-Unanimous Settlement Agreement ("Settlement Agreement") regarding the merger between Westar Energy, Inc. and Great Plains Energy Inc. ("Merger Order") approved by the Commission requires that Evergy and the Companies maintain separate capital structures and separate debt. The Merger Order noted that a key term of the Settlement Agreement was that, "Holdco, KCPL&L, and Westar will maintain separate capital structure and separate debt." The financial and ring-fencing commitments made by Evergy and the Companies in the Settlement Agreement are discussed in more detail in the testimony of Company witness Kirkland Andrews. As noted by Mr. Andrews, both of the Companies maintain separate capital structures and issue their own debt as required by the Settlement Agreement.

Second, both Companies have their own credit ratings and issue their own debt. As noted previously, EKM currently has an investment-grade long-term rating from S&P of A (Outlook: Negative) and from Moody's of Baa1 (Outlook: Stable).[70] EKC currently has an investment-grade long-term rating from S&P of A- (Outlook: Negative) and from

[70] S&P and Moody's Ratings, accessed February 7, 2023.

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Moody's of Baa1 (Outlook: Stable).[71] Therefore, the Companies are reasonably financially independent of their parent company.

Based on all of these factors, it is appropriate to use the Companies' actual capital structures for purposes of setting rates in this proceeding.

Q: Is there a basis for applying Evergy's capital structure or purposes of setting the Companies rates in this proceeding?

A: No. There is no basis to utilize the parent's capital structure as the ratemaking capital structure for the Companies. If the consolidated capital structure of Evergy were to be applied as the Companies' capital structures for ratemaking purposes, doing so would directly contradict the clearly stated intention to separate the Companies from Evergy in terms of capital structure and debt obligations as set forth in the Settlement Agreement and as required by the Commission.

Q: Is there any basis to rely on a hypothetical capital structure for the Companies?

A: No. As discussed previously, the stand-alone ratemaking principle suggests that the actual capital structure of the company should be relied upon, as long as the capital structure is reasonable. Further, the Companies' actual capital structures are consistent with those of the utility operating subsidiaries of the proxy group, there is also no reason to apply a hypothetical capital structure for ratemaking purposes.

Q: Did you conduct any analysis to determine the reasonableness of the Companies' projected actual capital structures?

A: Yes. In order to determine the reasonableness of the Companies' projected capital structures, I compared the Companies' proposals to the actual capital structures of the

[71] S&P and Moody's Ratings accessed February 7, 2023.

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utility operating subsidiaries of the companies in the proxy group. Since the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the average capital structure for the proxy group to benchmark the capital structures proposed by the Companies.

Q: How did you conduct this analysis?

A: I calculated the average proportion of common equity, long-term debt, and preferred equity for the most recent two years for each of the companies in the proxy group at the operating subsidiary level.[72] As shown in **Exhibit AEB-12**, the average common equity ratio for the operating subsidiaries of the proxy group companies was 52.58 percent (representing a range from 45.35 percent to 60.92 percent). The Companies' proposed equity ratios are generally consistent with the mean of the equity ratios for the utility operating subsidiaries of the proxy group companies. Therefore, I consider their proposals reasonable.

Q: Have you reviewed the Companies' proposed cost of debt?

A: Yes. I have. **Exhibit AEB-13** summarizes the long-term debt issued for EKC and EKM. As shown in this exhibit, I have compared the interest rates for each issuance to the yield on the Moody's A rated utility bond index and the yield on the Moody's Baa Utility bond index on the settlement date for each issuance. I then calculated the weighted average cost of the actual issuances, as compared to the weighted average cost if the issuances had been placed at the Moody's A rated utility bond yield ad the Moody's Baa utility bond yield at the time of issuance.

[72] Long-term debt includes the current portion of long-term debt, assuming that the current portion would be refinanced with debt at maturity.

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Q: What are your conclusions regarding the Companies' costs of long-term debt?

A: As shown in **Exhibit AEB-13**, the results of this analysis demonstrate that the debt issued by EKC and EKM has been below the yield on the Moody's A and Baa rated utility bond indexes. Therefore, I conclude that the weighted average cost of long-term debt issued for EKM and EKC are reasonable.

XI. CONCLUSIONS AND RECOMMENDATIONS

Q: What is your conclusion with respect to the Companies' proposed capital structures?

A: The Companies' proposed capital structures are within the range established by the proxy group companies. Taking into consideration the impact of current and projected market conditions on the cash flows of utilities as raised by the credit rating agencies, I conclude that the Companies' proposal is reasonable and should be adopted for ratemaking purposes.

Q: What is your conclusion regarding a fair ROE for the Companies?

A: Figure 13 summarizes the results of my cost of equity analyses. Based on the quantitative and qualitative analyses presented in my direct testimony, and the business and financial risks of the Companies as compared to the proxy group, the Companies' requested ROE of 10.25 percent is reasonable.

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Figure 13: Summary of Analytical Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Constant Growth DCF			
Mean Results:			
30-Day Avg. Stock Price	8.65%	9.85%	10.84%
90-Day Avg. Stock Price	8.58%	9.78%	10.77%
180-Day Avg. Stock Price	8.59%	9.79%	10.78%
Average	8.61%	9.80%	10.80%
Median Results:			
30-Day Avg. Stock Price	9.20%	9.62%	10.07%
90-Day Avg. Stock Price	9.09%	9.56%	10.01%
180-Day Avg. Stock Price	9.04%	9.50%	9.98%
Average	9.11%	9.56%	10.02%

	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM / ECAPM / Bond Yield Risk Premium			
CAPM:			
Current *Value Line* Beta	11.05%	11.05%	11.06%
Current Bloomberg Beta	10.49%	10.48%	10.50%
Long-term Avg. *Value Line* Beta	9.97%	9.96%	9.99%
ECAPM:			
Current *Value Line* Beta	11.31%	11.31%	11.32%
Current Bloomberg Beta	10.89%	10.89%	10.91%
Long-term Avg. *Value Line* Beta	10.50%	10.50%	10.52%
Bond Yield Risk Premium:	10.28%	10.26%	10.32%

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Q: What is your conclusion about the Companies' overall proposed weighted average cost of capital?

A: I have reviewed the capital structures as compared to the proxy group and determined that the proposed capitalization of the companies is reasonable as compared with the proxy group. In addition, I have evaluated the Companies' cost of debt as compared with the Moody's A and Baa rated utility bond indexes and determined that the issuances made at each Company were within the range established by these indexes and are therefore reasonable. Finally, the Companies' requested ROE is within the range and slightly lower than my recommended ROE. Therefore, I conclude that the weighted average cost of capital proposed by each of the companies is reasonable and appropriate.

Q: Does this conclude your direct testimony?

A: Yes, it does.

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Ann E. Bulkley

PRINCIPAL

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With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas sectors, including rate of return, cost of equity, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

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EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

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- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff. And prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of several hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

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- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost, and comparable sales approaches.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

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- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity

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Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity

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Connecticut Public Utilities Regulatory Authority				
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity

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Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity

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Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Kentucky Public Service Commission				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire

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SUMMARY OF COE ANALYTICAL RESULTS

	Constant Growth DCF		
	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	8.65%	9.85%	10.84%
90-Day Avg. Stock Price	8.58%	9.78%	10.77%
180-Day Avg. Stock Price	8.59%	9.79%	10.78%
Average	8.61%	9.80%	10.80%
Median Results:			
30-Day Avg. Stock Price	9.20%	9.62%	10.07%
90-Day Avg. Stock Price	9.09%	9.56%	10.01%
180-Day Avg. Stock Price	9.04%	9.50%	9 98%
Average	9.11%	9.56%	10.02%

	CAPM / ECAPM / Bond Yield Risk Premium		
	Current 30-Day Avg 30-Year Treasury Yield	Near-Term Projected 30-Year Treasury Yield	Longer-Term Projected 30-Year Treasury Yield
CAPM:			
Current *Value Line* Beta	11.05%	11.05%	11.06%

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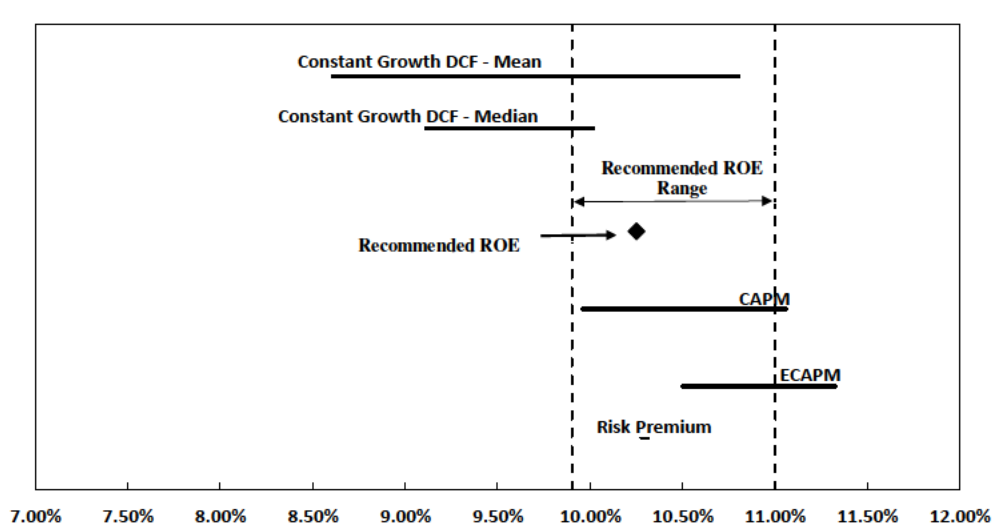
	X	Y
Constant Growth Mean DCF	8.61%	8.0
	9.80%	8.0
	10.80%	8.0
Constant Growth Median DCF	9.11%	7.0
	9.56%	7.0
	10.02%	7.0
CAPM	9.96%	3.5
	11.06%	3.5
ECAPM	10.50%	2.0
	11.32%	2.0
Risk Premium	10.27%	1.0
	10.31%	1.0
Low End ROE Recommendation	9.90%	0.0
	9.90%	9.0
High End ROE Recommendation	11.00%	0.0
	11.00%	9.0
Recommended ROE	10.25%	5.0



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PROXY GROUP SCREEN NG DATA AND RESULTS

Company	Ticker	[1] Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Covered by More Than 1 Analyst	[4] Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	[5] Generation Assets Included in Rate Base	[6] % Company-Owned Generation > 40%	[7] % Regulated Operating Income > 60%	[8] % Regulated Electric Operating Income > 60%	[9] Announced Merger
ALLETE, Inc.	ALE	Yes	BBB	Yes	Yes	Yes	41.54%	95.57%	97.40%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	70.97%	96.60%	91.18%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	76.04%	100.00%	85.03%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	52.91%	95.43%	100.00%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	Yes	59.38%	100.00%	76.10%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	41.36%	98.76%	68.14%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	Yes	82.34%	99.36%	90.89%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	68.34%	100.00%	99.41%	No
DACORP, Inc.	DA	Yes	BBB	Yes	Yes	Yes	68.95%	99.84%	100.00%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	96.85%	85.07%	100.00%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	56.48%	99.75%	84.22%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	55.06%	100.00%	100.00%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	55.70%	72.69%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	60.82%	100.00%	100.00%	No
Southern Company	SO	Yes	BBB+	Yes	Yes	Yes	77.81%	84.58%	80.48%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	57.64%	100.00%	86.47%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] Source: S&P Capital IQ Pro
[6] Source: S&P Capital IQ Pro
[7] Source: Form 10-K's for 2021, 2020, and 2019
[8] Source: Form 10-K's for 2021, 2020, and 2019
[9] Source: S&P Capital IQ Pro Financial News Releases
[10] OTTR: 2021 Operating Income Data was excluded from the three year average since, as noted by Otter Tail, 2021 operating income was impacted by the plastics segment that is not expected to continue over the long-term term.

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30-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.71	$62.25	4 35%	4 51%	6.00%	8.70%	7 30%	7 33%	10.48%	11.85%	13.24%
Alliant Energy Corporation	LNT	$1.81	$52.10	3.47%	3 58%	6.50%	5.55%	6.10%	6 05%	9.12%	9 63%	10.09%
Ameren Corporation	AEE	$2.52	$83.73	3 01%	3.11%	6.50%	6.70%	6 90%	6.70%	9.61%	9 81%	10.01%
American Electric Power Company, Inc.	AEP	$3.32	$89.54	3.71%	3 82%	6.00%	5.76%	6.10%	5 95%	9.57%	9.77%	9 92%
Avista Corporation	AVA	$1.84	$41.27	4.46%	4 56%	3.50%	5.20%	5 20%	4 63%	8.04%	9 20%	9.77%
CMS Energy Corporation	CMS	$1.95	$60.11	3 24%	3 37%	6.50%	8.00%	8 00%	7 50%	9.85%	10.87%	11.37%
Duke Energy Corporation	DUK	$4.02	$95.32	4 22%	4 33%	5.00%	5.30%	5.40%	5 23%	9.32%	9 56%	9.73%
Entergy Corporation	ETR	$4.28	$104 65	4 09%	4.18%	0.50%	6.60%	6 00%	4 37%	4.60%	8 55%	10.82%
IDACORP, Inc.	IDA	$3.16	$104 52	3 02%	3 08%	4.50%	3.00%	3 00%	3 50%	6.07%	6 58%	7 59%
NextEra Energy, Inc.	NEE	$1.87	$74.18	2 52%	2 65%	10 00%	11.00%	9 00%	10.00%	11 63%	12.65%	13.66%
NorthWestern Corporation	NWE	$2.56	$56.51	4 53%	4 60%	3.50%	4.50%	1.70%	3 23%	6.27%	7 84%	9.13%
OGE Energy Corporation	OGE	$1.66	$36.08	4 59%	4.78%	6.50%	Negative	10.20%	8 35%	11 24%	13.13%	15.02%
Otter Tail Corporation	OTTR	$1.75	$70.66	2.48%	2 56%	4.50%	9.00%	n/a	6.75%	7.03%	9 31%	11.59%
Portland General Electric Company	POR	$1.81	$47.26	3 83%	3 93%	5.00%	4.18%	6.10%	5 09%	8.09%	9 02%	10.05%
Southern Company	SO	$2.72	$66.16	4.11%	4 23%	6.50%	7.30%	4 00%	5 93%	8.19%	10.17%	11.56%
Xcel Energy Inc.	XEL	$2.08	$65.29	3.19%	3 29%	6.00%	6.40%	6 60%	6 33%	9.28%	9 62%	9 89%
Mean		$2.50	$69.35	3 68%	3.79%	5.44%	6.48%	6.11%	6 06%	8.65%	9 85%	10.84%
Median		$2.30	$65.72	3.77%	3 87%	6.00%	6.40%	6.10%	6 00%	9.20%	9 62%	10.07%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of March 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0 50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0 50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

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90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line EPS Growth	Yahoo! Finance EPS Growth	Zacks EPS Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.71	$62.91	4 31%	4.47%	6.00%	8.70%	7 30%	7 33%	10.44%	11.80%	13.20%
Alliant Energy Corporation	LNT	$1.81	$53.64	3 37%	3.48%	6.50%	5.55%	6.10%	6 05%	9.02%	9 53%	9 98%
Ameren Corporation	AEE	$2.52	$85.87	2 93%	3 03%	6.50%	6.70%	6 90%	6.70%	9.53%	9.73%	9 94%
American Electric Power Company, Inc.	AEP	$3.32	$92.26	3 60%	3.71%	6.00%	5.76%	6.10%	5 95%	9.46%	9 66%	9 81%
Avista Corporation	AVA	$1.84	$41.35	4.45%	4 55%	3.50%	5.20%	5 20%	4 63%	8.03%	9.19%	9.77%
CMS Energy Corporation	CMS	$1.95	$61.34	3.18%	3 30%	6.50%	8.00%	8 00%	7 50%	9.78%	10.80%	11.31%
Duke Energy Corporation	DUK	$4.02	$98.73	4 07%	4.18%	5.00%	5.30%	5.40%	5 23%	9.17%	9.41%	9 58%
Entergy Corporation	ETR	$4.28	$108.15	3 96%	4 04%	0.50%	6.60%	6 00%	4 37%	4.47%	8.41%	10.69%
IDACORP, Inc.	IDA	$3.16	$105.44	3 00%	3 05%	4.50%	3.00%	3 00%	3 50%	6.04%	6 55%	7 56%
NextEra Energy, Inc.	NEE	$1.87	$78.92	2 37%	2.49%	10 00%	11.00%	9 00%	10.00%	11.48%	12.49%	13.50%
NorthWestern Corporation	NWE	$2.56	$56.66	4 52%	4 59%	3.50%	4.50%	1.70%	3 23%	6.26%	7 82%	9.12%
OGE Energy Corporation	OGE	$1.66	$38.15	4 34%	4 52%	6.50%	Negative	10.20%	8 35%	10 98%	12.87%	14.76%
Otter Tail Corporation	OTTR	$1.75	$63.70	2.75%	2 84%	4.50%	9.00%	n/a	6.75%	7.31%	9 59%	11.87%
Portland General Electric Company	POR	$1.81	$47.48	3 81%	3 91%	5.00%	4.18%	6.10%	5 09%	8.07%	9 00%	10.03%
Southern Company	SO	$2.72	$67.39	4 04%	4.16%	6.50%	7.30%	4 00%	5 93%	8.12%	10.09%	11.48%
Xcel Energy Inc.	XEL	$2.08	$67.66	3 07%	3.17%	6.00%	6.40%	6 60%	6 33%	9.17%	9 50%	9.78%
Mean		$2.50	$70.60	3 61%	3.72%	5.44%	6.48%	6.11%	6 06%	8.58%	9.78%	10.77%
Median		$2.30	$65.54	3.71%	3 81%	6.00%	6.40%	6.10%	6 00%	9.09%	9 56%	10.01%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of March 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0 50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0 50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

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180-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line EPS Growth	[6] Yahoo! Finance EPS Growth	[7] Zacks EPS Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.71	$59.61	4 55%	4.71%	6.00%	8.70%	7 30%	7 33%	10 68%	12.05%	13.44%
Alliant Energy Corporation	LNT	$1.81	$54.98	3 29%	3 39%	6.50%	5.55%	6.10%	6 05%	8.93%	9.44%	9 90%
Ameren Corporation	AEE	$2.52	$85.90	2 93%	3 03%	6.50%	6.70%	6 90%	6.70%	9.53%	9.73%	9 94%
American Electric Power Company, Inc.	AEP	$3.32	$92.62	3 58%	3 69%	6.00%	5.76%	6.10%	5 95%	9.45%	9 64%	9.79%
Avista Corporation	AVA	$1.84	$40.35	4 56%	4 67%	3.50%	5.20%	5 20%	4 63%	8.14%	9 30%	9 88%
CMS Energy Corporation	CMS	$1.95	$61.79	3.16%	3 27%	6.50%	8.00%	8 00%	7 50%	9.76%	10.77%	11.28%
Duke Energy Corporation	DUK	$4.02	$98.99	4 06%	4.17%	5.00%	5.30%	5.40%	5 23%	9.16%	9.40%	9 57%
Entergy Corporation	ETR	$4.28	$108 67	3 94%	4 02%	0.50%	6.60%	6 00%	4 37%	4.45%	8 39%	10.67%
IDACORP, Inc.	IDA	$3.16	$104 92	3 01%	3 06%	4.50%	3.00%	3 00%	3 50%	6.06%	6 56%	7 58%
NextEra Energy, Inc.	NEE	$1.87	$80.19	2 33%	2.45%	10 00%	11.00%	9 00%	10.00%	11.44%	12.45%	13.46%
NorthWestern Corporation	NWE	$2.56	$54.32	4.71%	4.79%	3.50%	4.50%	1.70%	3 23%	6.45%	8 02%	9 32%
OGE Energy Corporation	OGE	$1.66	$38.20	4 34%	4 52%	6.50%	Negative	10.20%	8 35%	10 98%	12.87%	14.76%
Otter Tail Corporation	OTTR	$1.75	$65.49	2 67%	2.76%	4.50%	9.00%	n/a	6.75%	7.23%	9 51%	11.79%
Portland General Electric Company	POR	$1.81	$47.54	3 81%	3 90%	5.00%	4.18%	6.10%	5 09%	8.07%	9 00%	10.02%
Southern Company	SO	$2.72	$68.90	3 95%	4 07%	6.50%	7.30%	4 00%	5 93%	8.03%	10.00%	11.39%
Xcel Energy Inc.	XEL	$2.08	$67.99	3 06%	3.16%	6.00%	6.40%	6 60%	6 33%	9.15%	9.49%	9.76%
Mean		$2.50	$70.65	3 62%	3.73%	5.44%	6.48%	6.11%	6 06%	8.59%	9.79%	10.78%
Median		$2.30	$66.74	3.70%	3 80%	6.00%	6.40%	6.10%	6 00%	9.04%	9 50%	9 98%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of March 31, 2023
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0 50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0 50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

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CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.81%	0.90	12.11%	8.31%	11.28%	11.49%
Alliant Energy Corporation	LNT	3.81%	0.85	12.11%	8.31%	10.87%	11.18%
Ameren Corporation	AEE	3.81%	0.85	12.11%	8.31%	10.87%	11.18%
American Electric Power Company, Inc.	AEP	3.81%	0.75	12.11%	8.31%	10.04%	10.56%
Avista Corporation	AVA	3.81%	0.90	12.11%	8.31%	11.28%	11.49%
CMS Energy Corporation	CMS	3.81%	0.80	12.11%	8.31%	10.45%	10.87%
Duke Energy Corporation	DUK	3.81%	0.85	12.11%	8.31%	10.87%	11.18%
Entergy Corporation	ETR	3.81%	0.95	12.11%	8.31%	11.70%	11.80%
IDACORP, Inc.	IDA	3.81%	0.80	12.11%	8.31%	10.45%	10.87%
NextEra Energy, Inc.	NEE	3.81%	0.95	12.11%	8.31%	11.70%	11.80%
NorthWestern Corporation	NWE	3.81%	0.90	12.11%	8.31%	11.28%	11.49%
OGE Energy Corporation	OGE	3.81%	1.00	12.11%	8.31%	12.11%	12.11%
Otter Tail Corporation	OTTR	3.81%	0.90	12.11%	8.31%	11.28%	11.49%
Portland General Electric Company	POR	3.81%	0.85	12.11%	8.31%	10.87%	11.18%
Southern Company	SO	3.81%	0.90	12.11%	8.31%	11.28%	11.49%
Xcel Energy Inc.	XEL	3.81%	0.80	12.11%	8.31%	10.45%	10.87%
Mean			0.87			11.05%	11.31%
Median			0.88			11.07%	11.33%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2023
[2] Source: Value Line
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.78%	0.90	12.11%	8.33%	11.28%	11.49%
Alliant Energy Corporation	LNT	3.78%	0.85	12.11%	8.33%	10.86%	11.18%
Ameren Corporation	AEE	3.78%	0.85	12.11%	8.33%	10.86%	11.18%
American Electric Power Company, Inc.	AEP	3.78%	0.75	12.11%	8.33%	10.03%	10.55%
Avista Corporation	AVA	3.78%	0.90	12.11%	8.33%	11.28%	11.49%
CMS Energy Corporation	CMS	3.78%	0.80	12.11%	8.33%	10.45%	10.86%
Duke Energy Corporation	DUK	3.78%	0.85	12.11%	8.33%	10.86%	11.18%
Entergy Corporation	ETR	3.78%	0.95	12.11%	8.33%	11.70%	11.80%
IDACORP, Inc.	IDA	3.78%	0.80	12.11%	8.33%	10.45%	10.86%
NextEra Energy, Inc.	NEE	3.78%	0.95	12.11%	8.33%	11.70%	11.80%
NorthWestern Corporation	NWE	3.78%	0.90	12.11%	8.33%	11.28%	11.49%
OGE Energy Corporation	OGE	3.78%	1.00	12.11%	8.33%	12.11%	12.11%
Otter Tail Corporation	OTTR	3.78%	0.90	12.11%	8.33%	11.28%	11.49%
Portland General Electric Company	POR	3.78%	0.85	12.11%	8.33%	10.86%	11.18%
Southern Company	SO	3.78%	0.90	12.11%	8.33%	11.28%	11.49%
Xcel Energy Inc.	XEL	3.78%	0.80	12.11%	8.33%	10.45%	10.86%
Mean						11.05%	11.31%
Median						11.07%	11.33%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, March 31, 2023, at 2
[2] Source: Value Line
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.90%	0.90	12.11%	8.21%	11.29%	11.50%
Alliant Energy Corporation	LNT	3.90%	0.85	12.11%	8.21%	10.88%	11.19%
Ameren Corporation	AEE	3.90%	0.85	12.11%	8.21%	10.88%	11.19%
American Electric Power Company, Inc.	AEP	3.90%	0.75	12.11%	8.21%	10.06%	10.57%
Avista Corporation	AVA	3.90%	0.90	12.11%	8.21%	11.29%	11.50%
CMS Energy Corporation	CMS	3.90%	0.80	12.11%	8.21%	10.47%	10.88%
Duke Energy Corporation	DUK	3.90%	0.85	12.11%	8.21%	10.88%	11.19%
Entergy Corporation	ETR	3.90%	0.95	12.11%	8.21%	11.70%	11.80%
IDACORP, Inc.	IDA	3.90%	0.80	12.11%	8.21%	10.47%	10.88%
NextEra Energy, Inc.	NEE	3.90%	0.95	12.11%	8.21%	11.70%	11.80%
NorthWestern Corporation	NWE	3.90%	0.90	12.11%	8.21%	11.29%	11.50%
OGE Energy Corporation	OGE	3.90%	1.00	12.11%	8.21%	12.11%	12.11%
Otter Tail Corporation	OTTR	3.90%	0.90	12.11%	8.21%	11.29%	11.50%
Portland General Electric Company	POR	3.90%	0.85	12.11%	8.21%	10.88%	11.19%
Southern Company	SO	3.90%	0.90	12.11%	8.21%	11.29%	11.50%
Xcel Energy Inc.	XEL	3.90%	0.80	12.11%	8.21%	10.47%	10.88%
Mean						11.06%	11.32%
Median						11.09%	11.34%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 2, 2022, at 14
[2] Source: Value Line
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.81%	0.83	12.11%	8.31%	10.72%	11.06%
Alliant Energy Corporation	LNT	3.81%	0.80	12.11%	8.31%	10.43%	10.85%
Ameren Corporation	AEE	3.81%	0.76	12.11%	8.31%	10.11%	10.61%
American Electric Power Company, Inc.	AEP	3.81%	0.77	12.11%	8.31%	10.17%	10.66%
Avista Corporation	AVA	3.81%	0.76	12.11%	8.31%	10.09%	10.59%
CMS Energy Corporation	CMS	3.81%	0.76	12.11%	8.31%	10.09%	10.59%
Duke Energy Corporation	DUK	3.81%	0.72	12.11%	8.31%	9.83%	10.40%
Entergy Corporation	ETR	3.81%	0.86	12.11%	8.31%	10.93%	11.23%
IDACORP, Inc.	IDA	3.81%	0.80	12.11%	8.31%	10.49%	10.89%
NextEra Energy, Inc.	NEE	3.81%	0.82	12.11%	8.31%	10.63%	11.00%
NorthWestern Corporation	NWE	3.81%	0.86	12.11%	8.31%	10.97%	11.26%
OGE Energy Corporation	OGE	3.81%	0.93	12.11%	8.31%	11.52%	11.67%
Otter Tail Corporation	OTTR	3.81%	0.88	12.11%	8.31%	11.14%	11.38%
Portland General Electric Company	POR	3.81%	0.79	12.11%	8.31%	10.36%	10.80%
Southern Company	SO	3.81%	0.78	12.11%	8.31%	10.27%	10.73%
Xcel Energy Inc.	XEL	3.81%	0.75	12.11%	8.31%	10.03%	10.55%
Mean						10.49%	10.89%
Median						10.40%	10.83%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2023
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.78%	0.83	12.11%	8.33%	10.71%	11.06%
Alliant Energy Corporation	LNT	3.78%	0.80	12.11%	8.33%	10.42%	10.85%
Ameren Corporation	AEE	3.78%	0.76	12.11%	8.33%	10.10%	10.60%
American Electric Power Company, Inc.	AEP	3.78%	0.77	12.11%	8.33%	10.17%	10.65%
Avista Corporation	AVA	3.78%	0.76	12.11%	8.33%	10.08%	10.59%
CMS Energy Corporation	CMS	3.78%	0.76	12.11%	8.33%	10.08%	10.59%
Duke Energy Corporation	DUK	3.78%	0.72	12.11%	8.33%	9.82%	10.39%
Entergy Corporation	ETR	3.78%	0.86	12.11%	8.33%	10.93%	11.22%
IDACORP, Inc.	IDA	3.78%	0.80	12.11%	8.33%	10.48%	10.89%
NextEra Energy, Inc.	NEE	3.78%	0.82	12.11%	8.33%	10.63%	11.00%
NorthWestern Corporation	NWE	3.78%	0.86	12.11%	8.33%	10.97%	11.26%
OGE Energy Corporation	OGE	3.78%	0.93	12.11%	8.33%	11.51%	11.66%
Otter Tail Corporation	OTTR	3.78%	0.88	12.11%	8.33%	11.13%	11.38%
Portland General Electric Company	POR	3.78%	0.79	12.11%	8.33%	10.36%	10.80%
Southern Company	SO	3.78%	0.78	12.11%	8.33%	10.26%	10.73%
Xcel Energy Inc.	XEL	3.78%	0.75	12.11%	8.33%	10.02%	10.54%
Mean						10.48%	10.89%
Median						10.39%	10.82%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, March 31, 2023, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2024 - 2028)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] ROE (K)	[6] ECAPM ROE (K)
ALLETE, Inc.	ALE	3.90%	0.83	12.11%	8.21%	10.73%	11.08%
Alliant Energy Corporation	LNT	3.90%	0.80	12.11%	8.21%	10.45%	10.86%
Ameren Corporation	AEE	3.90%	0.76	12.11%	8.21%	10.13%	10.63%
American Electric Power Company, Inc.	AEP	3.90%	0.77	12.11%	8.21%	10.20%	10.68%
Avista Corporation	AVA	3.90%	0.76	12.11%	8.21%	10.11%	10.61%
CMS Energy Corporation	CMS	3.90%	0.76	12.11%	8.21%	10.11%	10.61%
Duke Energy Corporation	DUK	3.90%	0.72	12.11%	8.21%	9.85%	10.42%
Entergy Corporation	ETR	3.90%	0.86	12.11%	8.21%	10.94%	11.24%
IDACORP, Inc.	IDA	3.90%	0.80	12.11%	8.21%	10.51%	10.91%
NextEra Energy, Inc.	NEE	3.90%	0.82	12.11%	8.21%	10.65%	11.02%
NorthWestern Corporation	NWE	3.90%	0.86	12.11%	8.21%	10.99%	11.27%
OGE Energy Corporation	OGE	3.90%	0.93	12.11%	8.21%	11.52%	11.67%
Otter Tail Corporation	OTTR	3.90%	0.88	12.11%	8.21%	11.15%	11.39%
Portland General Electric Company	POR	3.90%	0.79	12.11%	8.21%	10.38%	10.82%
Southern Company	SO	3.90%	0.78	12.11%	8.21%	10.29%	10.75%
Xcel Energy Inc.	XEL	3.90%	0.75	12.11%	8.21%	10.05%	10.57%
Mean						10.50%	10.91%
Median						10.42%	10.84%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 2, 2022, at 14
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VALUE LINE LT AVERAGE BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.81%	0.79	12.11%	8.31%	10.33%	10.77%
Alliant Energy Corporation	LNT	3.81%	0.75	12.11%	8.31%	10.04%	10.56%
Ameren Corporation	AEE	3.81%	0.73	12.11%	8.31%	9.83%	10.40%
American Electric Power Company, Inc.	AEP	3.81%	0.68	12.11%	8.31%	9.41%	10.09%
Avista Corporation	AVA	3.81%	0.79	12.11%	8.31%	10.33%	10.77%
CMS Energy Corporation	CMS	3.81%	0.69	12.11%	8.31%	9.54%	10.18%
Duke Energy Corporation	DUK	3.81%	0.67	12.11%	8.31%	9.33%	10.03%
Entergy Corporation	ETR	3.81%	0.75	12.11%	8.31%	9.99%	10.52%
IDACORP, Inc.	IDA	3.81%	0.73	12.11%	8.31%	9.87%	10.43%
NextEra Energy, Inc.	NEE	3.81%	0.73	12.11%	8.31%	9.87%	10.43%
NorthWestern Corporation	NWE	3.81%	0.75	12.11%	8.31%	9.99%	10.52%
OGE Energy Corporation	OGE	3.81%	0.93	12.11%	8.31%	11.53%	11.68%
Otter Tail Corporation	OTTR	3.81%	0.85	12.11%	8.31%	10.87%	11.18%
Portland General Electric Company	POR	3.81%	0.75	12.11%	8.31%	10.04%	10.56%
Southern Company	SO	3.81%	0.66	12.11%	8.31%	9.25%	9.96%
Xcel Energy Inc.	XEL	3.81%	0.66	12.11%	8.31%	9.25%	9.96%
Mean						9.97%	10.50%
Median						9.93%	10.48%

Notes:
[1] Source: Bloomberg Professional, as of March 31, 2023
[2] Source: Exhibit AEB-5
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VALUE LINE LT AVERAGE BETA

$K = Rf + \beta (Rm - Rf)$
$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2023 - Q2 2024)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.78%	0.79	12.11%	8.33%	10.32%	10.77%
Alliant Energy Corporation	LNT	3.78%	0.75	12.11%	8.33%	10.03%	10.55%
Ameren Corporation	AEE	3.78%	0.73	12.11%	8.33%	9.82%	10.39%
American Electric Power Company, Inc.	AEP	3.78%	0.68	12.11%	8.33%	9.40%	10.08%
Avista Corporation	AVA	3.78%	0.79	12.11%	8.33%	10.32%	10.77%
CMS Energy Corporation	CMS	3.78%	0.69	12.11%	8.33%	9.53%	10.18%
Duke Energy Corporation	DUK	3.78%	0.67	12.11%	8.33%	9.32%	10.02%
Entergy Corporation	ETR	3.78%	0.75	12.11%	8.33%	9.99%	10.52%
IDACORP, Inc.	IDA	3.78%	0.73	12.11%	8.33%	9.86%	10.43%
NextEra Energy, Inc.	NEE	3.78%	0.73	12.11%	8.33%	9.86%	10.43%
NorthWestern Corporation	NWE	3.78%	0.75	12.11%	8.33%	9.99%	10.52%
OGE Energy Corporation	OGE	3.78%	0.93	12.11%	8.33%	11.53%	11.68%
Otter Tail Corporation	OTTR	3.78%	0.85	12.11%	8.33%	10.86%	11.18%
Portland General Electric Company	POR	3.78%	0.75	12.11%	8.33%	10.03%	10.55%
Southern Company	SO	3.78%	0.66	12.11%	8.33%	9.24%	9.96%
Xcel Energy Inc.	XEL	3.78%	0.66	12.11%	8.33%	9.24%	9.96%
Mean						9.96%	10.50%
Median						9.93%	10.47%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 42, No. 4, March 31, 2023, at 2
[2] Source: Exhibit AEB-5
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VALUE LINE LT BETA

$$K = Rf + \beta (Rm - Rf)$$
$$K = Rf + 0.25 \times (Rm - Rf) + 0.75 \times \beta \times (Rm - Rf)$$

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2024 - 2028)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.90%	0.79	12.11%	8.21%	10.35%	10.79%
Alliant Energy Corporation	LNT	3.90%	0.75	12.11%	8.21%	10.06%	10.57%
Ameren Corporation	AEE	3.90%	0.73	12.11%	8.21%	9.85%	10.42%
American Electric Power Company, Inc.	AEP	3.90%	0.68	12.11%	8.21%	9.44%	10.11%
Avista Corporation	AVA	3.90%	0.79	12.11%	8.21%	10.35%	10.79%
CMS Energy Corporation	CMS	3.90%	0.69	12.11%	8.21%	9.57%	10.20%
Duke Energy Corporation	DUK	3.90%	0.67	12.11%	8.21%	9.36%	10.05%
Entergy Corporation	ETR	3.90%	0.75	12.11%	8.21%	10.02%	10.54%
IDACORP, Inc.	IDA	3.90%	0.73	12.11%	8.21%	9.90%	10.45%
NextEra Energy, Inc.	NEE	3.90%	0.73	12.11%	8.21%	9.90%	10.45%
NorthWestern Corporation	NWE	3.90%	0.75	12.11%	8.21%	10.02%	10.54%
OGE Energy Corporation	OGE	3.90%	0.93	12.11%	8.21%	11.54%	11.68%
Otter Tail Corporation	OTTR	3.90%	0.85	12.11%	8.21%	10.88%	11.19%
Portland General Electric Company	POR	3.90%	0.75	12.11%	8.21%	10.06%	10.57%
Southern Company	SO	3.90%	0.66	12.11%	8.21%	9.28%	9.99%
Xcel Energy Inc.	XEL	3.90%	0.66	12.11%	8.21%	9.28%	9.99%
Mean						9.99%	10.52%
Median						9.96%	10.50%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 2, 2022, at 14
[2] Source: Exhibit AEB-5
[3] Source: Exhibit AEB-6
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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HISTORICAL BETA - 2013 - 2022

Company	Ticker	[1] 12/31/2013	[2] 12/31/2014	[3] 12/31/2015	[4] 12/31/2016	[5] 12/31/2017	[6] 12/31/2018	[7] 12/31/2019	[8] 12/31/2020	[9] 12/31/2021	[10] 12/31/2022	[11] Average
ALLETE, Inc.	ALE	0.75	0.80	0.80	0.75	0 80	0.65	0.65	0.85	0 90	0.90	0.79
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0 85	0.85	0.75
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0 80	0.85	0.73
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0 65	0.55	0.55	0.75	0.75	0.75	0 68
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0 95	0.90	0.79
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0 65	0.55	0.50	0.80	0 80	0.80	0 69
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0 60	0.50	0.50	0.85	0 85	0.85	0 67
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0 65	0.60	0.60	0.95	0 95	0.95	0.75
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0 80	0.80	0.73
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0 65	0.55	0.55	0.90	0 90	0.95	0.73
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0 95	0.90	0.75
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0 95	0.85	0.75	1.10	1 05	1.00	0 93
Otter Tail Corporation	OTTR	0.95	0.90	0.85	0.85	0 90	0.75	0.70	0.85	0 90	0.85	0 85
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0 90	0.85	0.75
Southern Company	SO	0.55	0.55	0.60	0.55	0 55	0.50	0.50	0.90	0 95	0.90	0 66
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0 60	0.50	0.50	0.80	0 80	0.80	0 66
Mean		0.73	0.74	0.75	0.69	0.70	0.59	0.58	0.88	0 88	0.87	0.74

Notes:
[1] Value Line, dated December 26, 2013.
[2] Value Line, dated December 31, 2014.
[3] Value Line, dated December 30, 2015.
[4] Value Line, dated December 29, 2016.
[5] Value Line, dated December 28, 2017.
[6] Value Line, dated December 27, 2018.
[7] Value Line, dated December 26, 2019.
[8] Value Line, dated December 30, 2020.
[9] Value Line, dated December 29, 2021.
[10] Value Line, dated December 30, 2022.
[11] Average ([1] - [10])

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MARKET RISK PREMIUM DERIVED FROM ANALYSTS' LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.76%
[2] Estimated Weighted Average Long-Term Growth Rate	10.26%
[3] S&P 500 Estimated Required Market Return	12.11%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	325.99	93.89	30,607.39	0.11%	5.07%	0.01%	3.00%	0.00%
American Express Co	AXP	744.07	164.95	122,733.69	0.43%	1.45%	0.01%	10.00%	0.04%
Verizon Communications Inc	VZ	4,200.00	38.89	163,338.00	0.57%	6.71%	0.04%	2.50%	0.01%
Broadcom Inc	AVGO	416.92	641.54	267,473.42		2.87%		30.00%	
Boeing Co/The	BA	599.18	212.43	127,283.17					
Caterpillar Inc	CAT	516.35	228.84	118,160.39	0.42%	2.10%	0.01%	10.50%	0.04%
JPMorgan Chase & Co	JPM	2,943.36	130.31	383,548.59	1.35%	3.07%	0.04%	5.00%	0.07%
Chevron Corp	CVX	1,906.67	163.16	311,092.93		3.70%		45.00%	
Coca-Cola Co/The	KO	4,326.31	62.03	268,360.76	0.94%	2.97%	0.03%	8.00%	0.08%
AbbVie Inc	ABBV	1,769.40	159.37	281,989.28	0.99%	3.71%	0.04%	2.00%	0.02%
Walt Disney Co/The	DIS	1,826.83	100.13	182,919.99				86.00%	
FleetCor Technologies Inc	FLT	73.49	210.85	15,495.79	0.05%			10.50%	0.01%
Extra Space Storage Inc	EXR	134.99	162.93	21,993.11	0.08%	3.98%	0.00%	6.50%	0.01%
Exxon Mobil Corp	XOM	4,070.99	109.66	446,424.22		3.32%			
Phillips 66	PSX	460.91	101.38	46,727.36		4.14%			
General Electric Co	GE	1,090.28	95.60	104,231.05		0.33%		21.00%	
HP Inc	HPQ	985.33	29.35	28,919.38	0.10%	3.58%	0.00%	12.50%	0.01%
Home Depot Inc/The	HD	1,014.96	295.12	299,533.81	1.05%	2.83%	0.03%	9.00%	0.09%
Monolithic Power Systems Inc	MPWR	47.31	500.54	23,678.04		0.80%		21.00%	
International Business Machines Corp	IBM	907.11	131.09	118,912.53	0.42%	5.03%	0.02%	3.00%	0.01%
Johnson & Johnson	JNJ	2,604.29	155.00	403,664.33	1.42%	2.92%	0.04%	8.00%	0.11%
McDonald's Corp	MCD	731.50	279.61	204,533.88	0.72%	2.17%	0.02%	9.00%	0.06%
Merck & Co Inc	MRK	2,538.59	106.39	270,080.80	0.95%	2.74%	0.03%	8.50%	0.08%
3M Co	MMM	551.47	105.11	57,964.91	0.20%	5.71%	0.01%	7.50%	0.02%
American Water Works Co Inc	AWK	194.64	146.49	28,513.25	0.10%	1.79%	0.00%	3.00%	0.00%
Bank of America Corp	BAC	8,003.84	28.60	228,909.80	0.80%	3.08%	0.02%	8.50%	0.07%
Pfizer Inc	PFE	5,644.40	40.80	230,291.60	0.81%	4.02%	0.03%	2.00%	0.02%
Procter & Gamble Co/The	PG	2,359.14	148.69	350,781.12	1.23%	2.46%	0.03%	5.50%	0.07%
AT&T Inc	T	7,129.87	19.25	137,250.00	0.48%	5.77%	0.03%	1.00%	0.00%
Travelers Cos Inc/The	TRV	232.09	171.41	39,783.23	0.14%	2.17%	0.00%	7.50%	0.01%
Raytheon Technologies Corp	RTX	1,463.21	97.93	143,291.96	0.50%	2.25%	0.01%	14.00%	0.07%
Analog Devices Inc	ADI	505.85	197.22	99,764.13	0.35%	1.74%	0.01%	11.50%	0.04%
Walmart Inc	WMT	2,695.66	147.45	397,474.48	1.40%	1.55%	0.02%	7.50%	0.10%
Cisco Systems Inc	CSCO	4,095.82	52.28	214,109.15	0.75%	2.98%	0.02%	8.50%	0.06%
Intel Corp	INTC	4,137.00	32.67	135,155.79		1.53%			
General Motors Co	GM	1,394.64	36.68	51,155.29	0.18%	0.98%	0.00%	8.50%	0.02%
Microsoft Corp	MSFT	7,443.80	288.30	2,146,048.69	7.55%	0.94%	0.07%	15.00%	1.13%
Dollar General Corp	DG	219.11	210.46	46,113.47	0.16%	1.12%	0.00%	10.00%	0.02%
Cigna Group/The	CI	297.03	255.53	75,900.84	0.27%	1.93%	0.01%	10.00%	0.03%
Kinder Morgan Inc	KMI	2,248.00	17.51	39,362.53	0.14%	6.34%	0.01%	18.50%	0.03%
Citigroup Inc	C	1,946.47	46.89	91,269.74	0.32%	4.35%	0.01%	3.50%	0.01%
American International Group Inc	AIG	733.67	50.36	36,947.52	0.13%	2.54%	0.00%	6.50%	0.01%
Altria Group Inc	MO	1,785.56	44.62	79,671.87	0.28%	8.43%	0.02%	6.00%	0.02%
HCA Healthcare Inc	HCA	277.26	263.68	73,106.60	0.26%	0.91%	0.00%	12.50%	0.03%
International Paper Co	IP	349.37	36.06	12,598.14	0.04%	5.13%	0.00%	9.50%	0.00%
Hewlett Packard Enterprise Co	HPE	1,295.87	15.93	20,643.19	0.07%	3.01%	0.00%	7.50%	0.01%
Abbott Laboratories	ABT	1,737.95	101.26	175,984.41	0.62%	2.01%	0.01%	6.50%	0.04%
Aflac Inc	AFL	611.71	64.52	39,467.40	0.14%	2.60%	0.00%	8.00%	0.01%
Air Products and Chemicals Inc	APD	222.08	287.21	63,784.46	0.22%	2.44%	0.01%	11.50%	0.03%
Royal Caribbean Cruises Ltd	RCL	255.35	65.30	16,674.42					
Hess Corp	HES	306.18	132.34	40,519.86		1.32%			
Archer-Daniels-Midland Co	ADM	546.45	79.66	43,529.81	0.15%	2.26%	0.00%	13.00%	0.02%
Automatic Data Processing Inc	ADP	414.35	222.63	92,247.19	0.32%	2.25%	0.01%	10.00%	0.03%
Verisk Analytics Inc	VRSK	154.70	191.86	29,679.97	0.10%	0.71%	0.00%	13.00%	0.01%
AutoZone Inc	AZO	18.40	2,458.15	45,225.04	0.16%			14.50%	0.02%
Avery Dennison Corp	AVY	81.11	178.93	14,512.83	0.05%	1.68%	0.00%	9.50%	0.00%
Enphase Energy Inc	ENPH	136.50	210.28	28,702.59				24.50%	
MSCI Inc	MSCI	80.06	559.69	44,810.46	0.16%	0.99%	0.00%	12.50%	0.02%
Ball Corp	BALL	314.40	55.11	17,326.31		1.45%		21.50%	
Ceridian HCM Holding Inc	CDAY	152.70	73.22	11,180.47					
Carrier Global Corp	CARR	834.95	45.75	38,199.01		1.62%			
Bank of New York Mellon Corp/The	BK	808.45	45.44	36,735.74	0.13%	3.26%	0.00%	6.00%	0.01%
Otis Worldwide Corp	OTIS	414.87	84.40	35,014.94		1.37%			
Baxter International Inc	BAX	505.52	40.56	20,504.01	0.07%	2.86%	0.00%	7.00%	0.01%
Becton Dickinson & Co	BDX	283.90	247.54	70,277.10	0.25%	1.47%	0.00%	4.50%	0.01%
Berkshire Hathaway Inc	BRK/B	1,298.19	308.77	400,842.13	1.41%			6.00%	0.08%
Best Buy Co Inc	BBY	218.05	78.27	17,066.46	0.06%	4.70%	0.00%	4.00%	0.00%
Boston Scientific Corp	BSX	1,437.33	50.03	71,909.52	0.25%			15.50%	0.04%
Bristol-Myers Squibb Co	BMY	2,098.78	69.31	145,466.16		3.29%			
Brown-Forman Corp	BF/B	310.00	64.27	19,923.76	0.07%	1.28%	0.00%	14.50%	0.01%
Coterra Energy Inc	CTRA	765.50	24.54	18,785.47		9.29%			
Campbell Soup Co	CPB	299.48	54.98	16,465.19	0.06%	2.69%	0.00%	5.00%	0.00%
Hilton Worldwide Holdings Inc	HLT	266.45	140.87	37,534.95		0.43%			
Carnival Corp	CCL	1,113.48	10.15	11,301.82					
Qorvo Inc	QRVO	99.89	101.57	10,145.73	0.04%			14.50%	0.01%
UDR Inc	UDR	329.17	41.06	13,515.56	0.05%	4.09%	0.00%	17.00%	0.01%
Clorox Co/The	CLX	123.53	158.24	19,546.60	0.07%	2.98%	0.00%	7.00%	0.00%
Paycom Software Inc	PAYC	60.31	304.01	18,333.63				21.00%	
CMS Energy Corp	CMS	291.26	61.38	17,877.78	0.06%	3.18%	0.00%	6.50%	0.00%

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Newell Brands Inc	NWL	413.60	12.44	5,145.18		7.40%			
Colgate-Palmolive Co	CL	832.14	75.15	62,535.17	0.22%	2.55%	0.01%	6.00%	0.01%
EPAM Systems Inc	EPAM	57.68	299.00	17,245.72				20.50%	
Comerica Inc	CMA	131.51	43.42	5,710.34	0.02%	6.54%	0.00%	8.50%	0.00%
Conagra Brands Inc	CAG	476.62	37.56	17,901.96	0.06%	3.51%	0.00%	3.50%	0.00%
Consolidated Edison Inc	ED	355.05	95.67	33,967.16	0.12%	3.39%	0.00%	4.50%	0.01%
Corning Inc	GLW	847.23	35.28	29,890.34	0.11%	3.17%	0.00%	17.50%	0.02%
Cummins Inc	CMI	141.54	238.88	33,811.08	0.12%	2.63%	0.00%	8.50%	0.01%
Caesars Entertainment Inc	CZR	215.18	48.81	10,502.98					
Danaher Corp	DHR	728.58	252.04	183,630.55	0.65%	0.43%	0.00%	16.00%	0.10%
Target Corp	TGT	460.36	165.63	76,250.09	0.27%	2.61%	0.01%	12.00%	0.03%
Deere & Co	DE	296.32	412.88	122,345.43	0.43%	1.21%	0.01%	12.50%	0.05%
Dominion Energy Inc	D	835.25	55.91	46,698.88	0.16%	4.78%	0.01%	4.00%	0.01%
Dover Corp	DOV	139.77	151.94	21,236.81	0.07%	1.33%	0.00%	9.00%	0.01%
Alliant Energy Corp	LNT	251.14	53.40	13,410.77	0.05%	3.39%	0.00%	6.00%	0.00%
Steel Dynamics Inc	STLD	171.58	113.06	19,398.61	0.07%	1.50%	0.00%	2.00%	0.00%
Duke Energy Corp	DUK	770.65	96.47	74,344.41	0.26%	4.17%	0.01%	5.00%	0.01%
Regency Centers Corp	REG	171.31	61.18	10,480.62	0.04%	4.25%	0.00%	10.50%	0.00%
Eaton Corp PLC	ETN	398.00	171.34	68,193.32	0.24%	2.01%	0.00%	12.00%	0.03%
Ecolab Inc	ECL	284.67	165.53	47,121.26	0.17%	1.28%	0.00%	6.00%	0.01%
PerkinElmer Inc	PKI	126.41	133.26	16,845.66	0.06%	0.21%	0.00%	4.00%	0.00%
Emerson Electric Co	EMR	571.40	87.14	49,791.80	0.18%	2.39%	0.00%	6.50%	0.01%
EOG Resources Inc	EOG	587.72	114.63	67,370.80		2.88%		26.00%	
Aon PLC	AON	205.14	315.29	64,679.22	0.23%	0.71%	0.00%	7.50%	0.02%
Entergy Corp	ETR	212.09	107.74	22,850.68	0.08%	3.97%	0.00%	0.50%	0.00%
Equifax Inc	EFX	123.23	202.84	24,995.36	0.09%	0.77%	0.00%	7.00%	0.01%
EQT Corp	EQT	360.36	31.91	11,499.09		1.88%			
IQVIA Holdings Inc	IQV	186.14	198.89	37,021.58	0.13%			14.50%	0.02%
Gartner Inc	IT	79.06	325.77	25,755.70	0.09%			17.50%	0.02%
FedEx Corp	FDX	251.35	228.49	57,431.42	0.20%	2.01%	0.00%	9.00%	0.02%
FMC Corp	FMC	125.14	122.13	15,283.59	0.05%	1.90%	0.00%	10.50%	0.01%
Brown & Brown Inc	BRO	283.70	57.42	16,289.94	0.06%	0.80%	0.00%	8.00%	0.00%
Ford Motor Co	F	3,915.33	12.60	49,333.16		4.76%		27.50%	
NextEra Energy Inc	NEE	1,987.50	77.08	153,196.11	0.54%	2.43%	0.01%	10.00%	0.05%
Franklin Resources Inc	BEN	500.36	26.94	13,479.64	0.05%	4.45%	0.00%	3.50%	0.00%
Garmin Ltd	GRMN	191.36	100.92	19,311.95	0.07%	2.89%	0.00%	5.00%	0.00%
Freeport-McMoRan Inc	FCX	1,430.69	40.91	58,529.69	0.21%	1.47%	0.00%	18.50%	0.04%
Dexcom Inc	DXCM	386.41	116.18	44,893.58					
General Dynamics Corp	GD	274.71	228.21	62,692.48	0.22%	2.31%	0.01%	9.50%	0.02%
General Mills Inc	GIS	587.35	85.46	50,195.27	0.18%	2.53%	0.00%	4.00%	0.01%
Genuine Parts Co	GPC	140.81	167.31	23,558.75	0.08%	2.27%	0.00%	10.50%	0.01%
Atmos Energy Corp	ATO	143.16	112.36	16,085.79	0.06%	2.63%	0.00%	7.00%	0.00%
WW Grainger Inc	GWW	50.26	688.81	34,621.66	0.12%	1.00%	0.00%	9.00%	0.01%
Halliburton Co	HAL	904.08	31.64	28,605.12		2.02%		32.50%	
L3Harris Technologies Inc	LHX	189.96	196.24	37,277.16	0.13%	2.32%	0.00%	17.00%	0.02%
Healthpeak Properties Inc	PEAK	546.99	21.97	12,017.44	0.04%	5.46%	0.00%	14.50%	0.01%
Insulet Corp	PODD	69.54	318.96	22,181.12					
Catalent Inc	CTLT	180.09	65.71	11,833.71				21.00%	
Fortive Corp	FTV	353.20	68.17	24,077.58	0.08%	0.41%	0.00%	12.00%	0.01%
Hershey Co/The	HSY	146.92	254.41	37,378.43	0.13%	1.63%	0.00%	9.00%	0.01%
Synchrony Financial	SYF	437.04	29.08	12,708.98	0.04%	3.16%	0.00%	9.50%	0.00%
Hormel Foods Corp	HRL	546.53	39.88	21,795.74	0.08%	2.76%	0.00%	7.50%	0.01%
Arthur J Gallagher & Co	AJG	214.08	191.31	40,954.69	0.14%	1.15%	0.00%	18.50%	0.03%
Mondelez International Inc	MDLZ	1,363.31	69.72	95,049.76	0.33%	2.21%	0.01%	7.50%	0.03%
CenterPoint Energy Inc	CNP	629.43	29.46	18,543.07	0.07%	2.58%	0.00%	6.50%	0.00%
Humana Inc	HUM	124.98	485.46	60,670.36	0.21%	0.73%	0.00%	12.50%	0.03%
Willis Towers Watson PLC	WTW	106.58	232.38	24,766.60	0.09%	1.45%	0.00%	8.50%	0.01%
Illinois Tool Works Inc	ITW	304.82	243.45	74,208.67	0.26%	2.15%	0.01%	11.00%	0.03%
CDW Corp/DE	CDW	135.59	194.89	26,425.52	0.09%	1.21%	0.00%	8.50%	0.01%
Trane Technologies PLC	TT	229.08	183.98	42,145.22		1.63%			
Interpublic Group of Cos Inc/The	IPG	385.11	37.24	14,341.42	0.05%	3.33%	0.00%	10.00%	0.01%
International Flavors & Fragrances Inc	IFF	255.07	91.96	23,455.96	0.08%	3.52%	0.00%	6.00%	0.00%
Generac Holdings Inc	GNRC	61.89	108.01	6,684.41	0.02%			19.00%	0.00%
NXP Semiconductors NV	NXPI	259.52	186.48	48,393.81	0.17%	2.18%	0.00%	11.00%	0.02%
Kellogg Co	K	342.67	66.96	22,945.05	0.08%	3.52%	0.00%	3.50%	0.00%
Broadridge Financial Solutions Inc	BR	117.69	146.57	17,250.26	0.06%	1.98%	0.00%	8.50%	0.01%
Kimberly-Clark Corp	KMB	337.45	134.22	45,293.08	0.16%	3.52%	0.01%	7.00%	0.01%
Kimco Realty Corp	KIM	618.46	19.53	12,078.54	0.04%	4.71%	0.00%	11.00%	0.00%
Oracle Corp	ORCL	2,699.80	92.92	250,865.60	0.88%	1.72%	0.02%	10.00%	0.09%
Kroger Co/The	KR	717.47	49.37	35,421.40	0.12%	2.11%	0.00%	6.50%	0.01%
Lennar Corp	LEN	252.47	105.11	26,536.70	0.09%	1.43%	0.00%	8.50%	0.01%
Eli Lilly & Co	LLY	950.30	343.42	326,350.65	1.15%	1.32%	0.02%	11.50%	0.13%
Bath & Body Works Inc	BBWI	228.77	36.58	8,368.26		2.19%		26.50%	
Charter Communications Inc	CHTR	152.65	357.61	54,589.52	0.19%			15.50%	0.03%
Lincoln National Corp	LNC	169.22	22.47	3,802.40		8.01%		30.50%	
Loews Corp	L	230.88	58.02	13,395.43	0.05%	0.43%	0.00%	18.50%	0.01%
Lowe's Cos Inc	LOW	596.36	199.97	119,253.31	0.42%	2.10%	0.01%	11.00%	0.05%
IDEX Corp	IEX	75.52	231.03	17,446.92	0.06%	1.04%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	494.57	166.55	82,370.80	0.29%	1.42%	0.00%	11.00%	0.03%
Masco Corp	MAS	225.20	49.72	11,197.09	0.04%	2.29%	0.00%	8.00%	0.00%
S&P Global Inc	SPGI	327.95	344.77	113,066.29	0.40%	1.04%	0.00%	6.50%	0.03%
Medtronic PLC	MDT	1,330.42	80.62	107,258.78	0.38%	3.37%	0.01%	7.50%	0.03%
Viatris Inc	VTRS	1,196.81	9.62	11,513.35		4.99%			
CVS Health Corp	CVS	1,284.11	74.31	95,422.36	0.34%	3.26%	0.01%	6.00%	0.02%
DuPont de Nemours Inc	DD	458.34	71.77	32,894.92	0.12%	2.01%	0.00%	10.00%	0.01%
Micron Technology Inc	MU	1,094.39	60.34	66,035.73	0.23%	0.76%	0.00%	9.50%	0.02%
Motorola Solutions Inc	MSI	167.47	286.13	47,917.33	0.17%	1.23%	0.00%	10.50%	0.02%
Cboe Global Markets Inc	CBOE	105.74	134.24	14,194.94	0.05%	1.49%	0.00%	10.00%	0.00%
Laboratory Corp of America Holdings	LH	88.50	229.42	20,303.90	0.07%	1.26%	0.00%	1.50%	0.00%
Newmont Corp	NEM	794.51	49.02	38,946.83	0.14%	3.26%	0.00%	8.00%	0.01%

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
NIKE Inc	NKE	1,245.67	122.64	152,768.48		1.11%		24.00%	
NiSource Inc	NI	412.51	27.96	11,533.72	0.04%	3.58%	0.00%	9.50%	0.00%
Norfolk Southern Corp	NSC	227.78	212.00	48,289.78	0.17%	2.55%	0.00%	10.00%	0.02%
Principal Financial Group Inc	PFG	243.10	74.32	18,067.49	0.06%	3.44%	0.00%	6.50%	0.00%
Eversource Energy	ES	348.67	78.26	27,287.15	0.10%	3.45%	0.00%	6.50%	0.01%
Northrop Grumman Corp	NOC	152.09	461.72	70,221.61	0.25%	1.50%	0.00%	9.50%	0.02%
Wells Fargo & Co	WFC	3,777.09	37.38	141,187.55	0.50%	3.21%	0.02%	12.00%	0.06%
Nucor Corp	NUE	251.93	154.47	38,915.47	0.14%	1.32%	0.00%	9.50%	0.01%
Occidental Petroleum Corp	OXY	898.12	62.43	56,069.32		1.15%			
Omnicom Group Inc	OMC	201.41	94.34	19,000.93	0.07%	2.97%	0.00%	6.50%	0.00%
ONEOK Inc	OKE	447.22	63.54	28,416.42	0.10%	6.01%	0.01%	11.50%	0.01%
Raymond James Financial Inc	RJF	215.35	93.27	20,085.88	0.07%	1.80%	0.00%	15.00%	0.01%
PG&E Corp	PCG	1,988.47	16.17	32,153.48	0.11%			7.50%	0.01%
Parker-Hannifin Corp	PH	128.27	336.11	43,111.49	0.15%	1.58%	0.00%	15.50%	0.02%
Rollins Inc	ROL	492.74	37.53	18,492.68	0.07%	1.39%	0.00%	10.50%	0.01%
PPL Corp	PPL	736.68	27.79	20,472.28	0.07%	3.45%	0.00%	3.50%	0.00%
ConocoPhillips	COP	1,217.38	99.21	120,776.57	0.42%	0.60%	0.00%	20.00%	0.08%
PulteGroup Inc	PHM	224.31	58.28	13,072.85	0.05%	1.10%	0.00%	7.00%	0.00%
Pinnacle West Capital Corp	PNW	113.18	79.24	8,968.07	0.03%	4.37%	0.00%	0.50%	0.00%
PNC Financial Services Group Inc/The	PNC	399.75	127.10	50,808.61	0.18%	4.72%	0.01%	12.00%	0.02%
PPG Industries Inc	PPG	235.36	133.58	31,439.12	0.11%	1.86%	0.00%	4.00%	0.00%
Progressive Corp/The	PGR	585.37	143.06	83,742.46	0.29%	0.28%	0.00%	6.50%	0.02%
Public Service Enterprise Group Inc	PEG	498.77	62.45	31,148.19	0.11%	3.65%	0.00%	4.50%	0.00%
Robert Half International Inc	RHI	107.70	80.57	8,677.23	0.03%	2.38%	0.00%	9.50%	0.00%
Edison International	EIX	382.63	70.59	27,009.64	0.09%	4.18%	0.00%	16.00%	0.02%
Schlumberger NV	SLB	1,427.60	49.10	70,095.26		2.04%		28.50%	
Charles Schwab Corp/The	SCHW	1,791.45	52.38	93,836.05	0.33%	1.91%	0.01%	9.00%	0.03%
Sherwin-Williams Co/The	SHW	258.44	224.77	58,090.01	0.20%	1.08%	0.00%	7.00%	0.01%
West Pharmaceutical Services Inc	WST	74.14	346.47	25,685.90	0.09%	0.22%	0.00%	17.00%	0.02%
J M Smucker Co/The	SJM	106.64	157.37	16,781.31	0.06%	2.59%	0.00%	4.00%	0.00%
Snap-on Inc	SNA	53.13	246.89	13,117.02	0.05%	2.62%	0.00%	4.50%	0.00%
AMETEK Inc	AME	230.09	145.33	33,439.56	0.12%	0.69%	0.00%	10.00%	0.01%
Southern Co/The	SO	1,088.67	69.58	75,749.87	0.27%	3.91%	0.01%	6.50%	0.02%
Truist Financial Corp	TFC	1,328.14	34.10	45,289.57	0.16%	6.10%	0.01%	5.50%	0.01%
Southwest Airlines Co	LUV	594.29	32.54	19,338.10		2.21%			
W R Berkley Corp	WRB	263.45	62.26	16,402.15	0.06%	0.64%	0.00%	17.50%	0.01%
Stanley Black & Decker Inc	SWK	153.06	80.58	12,333.17	0.04%	3.97%	0.00%	6.00%	0.00%
Public Storage	PSA	175.80	302.14	53,114.70	0.19%	3.97%	0.01%	7.50%	0.01%
Arista Networks Inc	ANET	306.40	167.86	51,431.46	0.18%			10.00%	0.02%
Sysco Corp	SYY	507.60	77.23	39,202.26		2.54%		21.50%	
Corteva Inc	CTVA	712.61	60.31	42,977.21	0.15%	0.99%	0.00%	15.50%	0.02%
Texas Instruments Inc	TXN	907.34	186.01	168,774.69	0.59%	2.67%	0.02%	4.50%	0.03%
Textron Inc	TXT	203.66	70.63	14,384.51	0.05%	0.11%	0.00%	10.50%	0.01%
Thermo Fisher Scientific Inc	TMO	385.43	576.37	222,150.29	0.78%	0.24%	0.00%	11.00%	0.09%
TJX Cos Inc/The	TJX	1,152.57	78.36	90,315.31	0.32%	1.70%	0.01%	17.00%	0.05%
Globe Life Inc	GL	96.52	110.02	10,619.24	0.04%	0.82%	0.00%	8.50%	0.00%
Johnson Controls International plc	JCI	687.21	60.22	41,384.03	0.15%	2.39%	0.00%	12.50%	0.02%
Ulta Beauty Inc	ULTA	50.20	545.67	27,389.91	0.10%			16.50%	0.02%
Union Pacific Corp	UNP	611.87	201.26	123,145.56	0.43%	2.58%	0.01%	9.50%	0.04%
Keysight Technologies Inc	KEYS	178.14	161.48	28,765.89	0.10%			13.00%	0.01%
UnitedHealth Group Inc	UNH	932.85	472.59	440,854.16	1.55%	1.40%	0.02%	12.00%	0.19%
Marathon Oil Corp	MRO	629.65	23.96	15,086.51		1.67%			
Bio-Rad Laboratories Inc	BIO	24.52	479.02	11,746.53	0.04%			11.50%	0.00%
Ventas Inc	VTR	399.99	43.35	17,339.74		4.15%		23.50%	
VF Corp	VFC	388.66	22.91	8,904.13	0.03%	5.24%	0.00%	9.00%	0.00%
Vulcan Materials Co	VMC	133.06	171.56	22,827.26	0.08%	1.00%	0.00%	9.00%	0.01%
Weyerhaeuser Co	WY	732.89	30.13	22,082.04	0.08%	2.52%	0.00%	5.00%	0.00%
Whirlpool Corp	WHR	54.50	132.02	7,195.35	0.03%	5.30%	0.00%	6.00%	0.00%
Williams Cos Inc/The	WMB	1,218.81	29.86	36,393.73	0.13%	5.99%	0.01%	11.00%	0.01%
Constellation Energy Corp	CEG	326.66	78.50	25,643.12		1.44%			
WEC Energy Group Inc	WEC	315.44	94.79	29,900.08	0.11%	3.29%	0.00%	6.00%	0.01%
Adobe Inc	ADBE	458.70	385.37	176,769.22	0.62%			13.00%	0.08%
AES Corp/The	AES	669.03	24.08	16,110.27	0.06%	2.76%	0.00%	14.00%	0.01%
Amgen Inc	AMGN	533.98	241.75	129,088.70	0.45%	3.52%	0.02%	5.50%	0.02%
Apple Inc	AAPL	15,821.95	164.90	2,609,038.90	9.17%	0.56%	0.05%	10.50%	0.96%
Autodesk Inc	ADSK	214.78	208.16	44,709.23	0.16%			14.00%	0.02%
Cintas Corp	CTAS	101.67	462.68	47,041.60	0.17%	0.99%	0.00%	14.00%	0.02%
Comcast Corp	CMCSA	4,206.61	37.91	159,472.66	0.56%	3.06%	0.02%	8.50%	0.05%
Molson Coors Beverage Co	TAP	200.03	51.68	10,337.40		3.17%		49.50%	
KLA Corp	KLAC	138.48	399.17	55,277.06	0.19%	1.30%	0.00%	20.00%	0.04%
Marriott International Inc/MD	MAR	308.88	166.04	51,287.10	0.18%	0.96%	0.00%	17.50%	0.03%
McCormick & Co Inc/MD	MKC	250.84	83.21	20,872.23	0.07%	1.87%	0.00%	4.50%	0.00%
PACCAR Inc	PCAR	522.56	73.20	38,251.03	0.13%	1.37%	0.00%	5.00%	0.01%
Costco Wholesale Corp	COST	443.48	496.87	220,353.40	0.77%	0.72%	0.01%	10.50%	0.08%
First Republic Bank/CA	FRC	186.22	13.99	2,605.20	0.01%			11.50%	0.00%
Stryker Corp	SYK	378.83	285.47	108,144.89	0.38%	1.05%	0.00%	6.50%	0.02%
Tyson Foods Inc	TSN	285.62	59.32	16,942.74	0.06%	3.24%	0.00%	6.00%	0.00%
Lamb Weston Holdings Inc	LW	147.82	104.52	15,450.46	0.05%	1.07%	0.00%	11.50%	0.01%
Applied Materials Inc	AMAT	845.12	122.83	103,805.84	0.37%	1.04%	0.00%	10.50%	0.04%
American Airlines Group Inc	AAL	652.82	14.75	9,629.04					
Cardinal Health Inc	CAH	257.64	75.50	19,451.74	0.07%	2.63%	0.00%	5.00%	0.00%
Cincinnati Financial Corp	CINF	157.18	112.08	17,616.29	0.06%	2.68%	0.00%	9.00%	0.01%
Paramount Global	PARA	609.81	22.31	13,604.91	0.05%	4.30%	0.00%	4.50%	0.00%
DR Horton Inc	DHI	343.39	97.69	33,546.06	0.12%	1.02%	0.00%	1.00%	0.00%
Electronic Arts Inc	EA	274.23	120.45	33,030.76	0.12%	0.63%	0.00%	13.00%	0.02%
Fair Isaac Corp	FICO	25.16	702.69	17,676.17	0.06%			16.00%	0.01%
Expeditors International of Washington Inc	EXPD	154.40	110.12	17,002.31	0.06%	1.22%	0.00%	10.00%	0.01%
Fastenal Co	FAST	570.96	53.94	30,797.64	0.11%	2.60%	0.00%	6.50%	0.01%
M&T Bank Corp	MTB	168.04	119.57	20,093.02	0.07%	4.35%	0.00%	9.00%	0.01%
Xcel Energy Inc	XEL	549.85	67.44	37,081.68	0.13%	3.08%	0.00%	6.00%	0.01%

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Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Fiserv Inc	FISV	628.13	113.03	70,997.08	0.25%			11.00%	0.03%
Fifth Third Bancorp	FITB	681.05	26.64	18,143.28	0.06%	4.95%	0.00%	10.00%	0.01%
Gilead Sciences Inc	GILD	1,248.82	82.97	103,614.26	0.36%	3.62%	0.01%	12.00%	0.04%
Hasbro Inc	HAS	138.22	53.69	7,421.03	0.03%	5.22%	0.00%	7.50%	0.00%
Huntington Bancshares Inc/OH	HBAN	1,449.64	11.20	16,235.93	0.06%	5.54%	0.00%	12.50%	0.01%
Welltower Inc	WELL	490.64	71.69	35,174.27	0.12%	3.40%	0.00%	12.00%	0.01%
Biogen Inc	BIIB	144.49	278.03	40,171.44				-10.50%	
Northern Trust Corp	NTRS	207.75	88.13	18,309.10	0.06%	3.40%	0.00%	8.00%	0.01%
Packaging Corp of America	PKG	89.88	138.83	12,478.60	0.04%	3.60%	0.00%	11.00%	0.00%
Paychex Inc	PAYX	360.51	114.59	41,310.73	0.15%	2.76%	0.00%	10.50%	0.02%
QUALCOMM Inc	QCOM	1,115.00	127.58	142,251.70	0.50%	2.35%	0.01%	9.50%	0.05%
Roper Technologies Inc	ROP	106.24	440.69	46,820.23	0.16%	0.62%	0.00%	3.50%	0.01%
Ross Stores Inc	ROST	342.05	106.13	36,301.55	0.13%	1.26%	0.00%	14.00%	0.02%
IDEXX Laboratories Inc	IDXX	82.90	500.08	41,458.13	0.15%			11.50%	0.02%
Starbucks Corp	SBUX	1,149.30	104.13	119,676.61	0.42%	2.04%	0.01%	16.00%	0.07%
KeyCorp	KEY	924.86	12.52	11,579.23	0.04%	6.55%	0.00%	7.50%	0.00%
Fox Corp	FOXA	296.92	34.05	10,110.02	0.04%	1.47%	0.00%	12.00%	0.00%
Fox Corp	FOX	237.64	31.31	7,440.63		1.60%			
State Street Corp	STT	344.48	75.69	26,073.62	0.09%	3.33%	0.00%	8.50%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	421.93	13.45	5,674.96					
US Bancorp	USB	1,531.12	36.05	55,196.88	0.19%	5.33%	0.01%	7.00%	0.01%
A O Smith Corp	AOS	125.01	69.15	8,644.44	0.03%	1.74%	0.00%	11.50%	0.00%
Gen Digital Inc	GEN	639.13	17.16	10,967.45	0.04%	2.91%	0.00%	10.50%	0.00%
T Rowe Price Group Inc	TROW	224.51	112.90	25,347.63	0.09%	4.32%	0.00%	4.50%	0.00%
Waste Management Inc	WM	406.77	163.17	66,372.17	0.23%	1.72%	0.00%	6.50%	0.02%
Constellation Brands Inc	STZ	184.50	225.89	41,676.25	0.15%	1.42%	0.00%	6.00%	0.01%
DENTSPLY SIRONA Inc	XRAY	215.36	39.28	8,459.42	0.03%	1.43%	0.00%	12.00%	0.00%
Zions Bancorp NA	ZION	148.10	29.93	4,432.60	0.02%	5.48%	0.00%	6.50%	0.00%
Alaska Air Group Inc	ALK	127.47	41.96	5,348.43					
Invesco Ltd	IVZ	454.72	16.40	7,457.47	0.03%	4.57%	0.00%	10.00%	0.00%
Intuit Inc	INTU	280.55	445.83	125,075.82	0.44%	0.70%	0.00%	16.50%	0.07%
Morgan Stanley	MS	1,681.94	87.80	147,674.33	0.52%	3.53%	0.02%	8.50%	0.04%
Microchip Technology Inc	MCHP	547.80	83.78	45,894.35	0.16%	1.71%	0.00%	10.00%	0.02%
Chubb Ltd	CB	413.51	194.18	80,294.60	0.28%	1.71%	0.00%	14.50%	0.04%
Hologic Inc	HOLX	246.55	80.70	19,896.67				25.00%	
Citizens Financial Group Inc	CFG	484.31	30.37	14,708.46	0.05%	5.53%	0.00%	8.00%	0.00%
O'Reilly Automotive Inc	ORLY	61.57	848.98	52,269.15	0.18%			13.00%	0.02%
Allstate Corp/The	ALL	263.33	110.81	29,179.60	0.10%	3.21%	0.00%	2.50%	0.00%
Equity Residential	EQR	378.60	60.00	22,716.18		4.42%		-5.00%	
BorgWarner Inc	BWA	233.79	49.11	11,481.18	0.04%	1.38%	0.00%	9.50%	0.00%
Keurig Dr Pepper Inc	KDP	1,406.45	35.28	49,619.45	0.17%	2.27%	0.00%	11.50%	0.02%
Organon & Co	OGN	254.38	23.52	5,983.09		4.76%			
Host Hotels & Resorts Inc	HST	713.48	16.49	11,765.27		2.91%		51.00%	
Incyte Corp	INCY	222.97	72.27	16,113.68				27.00%	
Simon Property Group Inc	SPG	326.73	111.97	36,584.18	0.13%	6.43%	0.01%	3.50%	0.00%
Eastman Chemical Co	EMN	119.14	84.34	10,048.10	0.04%	3.75%	0.00%	7.00%	0.00%
AvalonBay Communities Inc	AVB	139.92	168.06	23,514.96	0.08%	3.93%	0.00%	7.00%	0.01%
Prudential Financial Inc	PRU	366.97	82.74	30,363.43	0.11%	6.04%	0.01%	3.00%	0.00%
United Parcel Service Inc	UPS	723.30	193.99	140,312.77	0.49%	3.34%	0.02%	7.50%	0.04%
Walgreens Boots Alliance Inc	WBA	862.80	34.58	29,835.49	0.10%	5.55%	0.01%	3.00%	0.00%
STERIS PLC	STE	99.28	191.28	18,991.04	0.07%	0.98%	0.00%	10.00%	0.01%
McKesson Corp	MCK	136.94	356.05	48,757.13	0.17%	0.61%	0.00%	10.00%	0.02%
Lockheed Martin Corp	LMT	254.52	472.73	120,318.77	0.42%	2.54%	0.01%	7.00%	0.03%
AmerisourceBergen Corp	ABC	202.26	160.11	32,383.53	0.11%	1.21%	0.00%	8.50%	0.01%
Capital One Financial Corp	COF	381.08	96.16	36,644.65		2.50%			
Waters Corp	WAT	58.94	309.63	18,250.83	0.06%			6.00%	0.00%
Nordson Corp	NDSN	57.26	222.26	12,726.83	0.04%	1.17%	0.00%	12.00%	0.01%
Dollar Tree Inc	DLTR	221.23	143.55	31,757.28	0.11%			12.00%	0.01%
Darden Restaurants Inc	DRI	121.71	155.16	18,883.75	0.07%	3.12%	0.00%	17.50%	0.01%
Evergy Inc	EVRG	229.58	61.12	14,032.11	0.05%	4.01%	0.00%	7.50%	0.00%
Match Group Inc	MTCH	279.32	38.39	10,723.25				21.00%	
Domino's Pizza Inc	DPZ	35.42	329.87	11,683.34	0.04%	1.47%	0.00%	13.00%	0.01%
NVR Inc	NVR	3.25	5,572.19	18,104.05	0.06%			5.50%	0.00%
NetApp Inc	NTAP	213.91	63.85	13,657.83	0.05%	3.13%	0.00%	8.50%	0.00%
DXC Technology Co	DXC	227.68	25.56	5,819.55	0.02%			12.00%	0.00%
Old Dominion Freight Line Inc	ODFL	110.03	340.84	37,501.26	0.13%	0.47%	0.00%	12.50%	0.02%
DaVita Inc	DVA	90.40	81.11	7,332.34	0.03%			7.50%	0.00%
Hartford Financial Services Group Inc/The	HIG	313.06	69.69	21,816.94	0.08%	2.44%	0.00%	6.50%	0.00%
Iron Mountain Inc	IRM	291.57	52.91	15,427.18	0.05%	4.68%	0.00%	10.00%	0.01%
Estee Lauder Cos Inc/The	EL	231.68	246.46	57,099.36	0.20%	1.07%	0.00%	14.00%	0.03%
Cadence Design Systems Inc	CDNS	272.94	210.09	57,341.96	0.20%			12.00%	0.02%
Tyler Technologies Inc	TYL	41.82	354.64	14,830.69	0.05%			12.00%	0.01%
Universal Health Services Inc	UHS	63.42	127.10	8,060.30	0.03%	0.63%	0.00%	5.50%	0.00%
Skyworks Solutions Inc	SWKS	159.15	117.98	18,776.87	0.07%	2.10%	0.00%	9.00%	0.01%
Quest Diagnostics Inc	DGX	111.32	141.48	15,749.98	0.06%	2.01%	0.00%	5.00%	0.00%
Activision Blizzard Inc	ATVI	784.27	85.59	67,126.01	0.24%	0.55%	0.00%	11.50%	0.03%
Rockwell Automation Inc	ROK	114.78	293.45	33,682.78	0.12%	1.61%	0.00%	9.50%	0.01%
Kraft Heinz Co/The	KHC	1,227.00	38.67	47,448.05	0.17%	4.14%	0.01%	6.50%	0.01%
American Tower Corp	AMT	465.65	204.34	95,150.10	0.33%	3.05%	0.01%	6.00%	0.02%
Regeneron Pharmaceuticals Inc	REGN	107.51	821.67	88,335.28	0.31%			5.00%	0.02%
Amazon.com Inc	AMZN	10,247.26	103.29	1,058,439.49				26.50%	
Jack Henry & Associates Inc	JKHY	72.99	150.72	11,001.20	0.04%	1.38%	0.00%	8.50%	0.00%
Ralph Lauren Corp	RL	41.10	116.67	4,794.90	0.02%	2.57%	0.00%	12.00%	0.00%
Boston Properties Inc	BXP	156.82	54.12	8,487.26		7.24%		-1.00%	
Amphenol Corp	APH	594.61	81.72	48,591.12	0.17%	1.03%	0.00%	12.50%	0.02%
Howmet Aerospace Inc	HWM	411.80	42.37	17,448.14	0.06%	0.38%	0.00%	14.00%	0.01%
Pioneer Natural Resources Co	PXD	235.00	204.24	47,997.22		10.93%		21.00%	
Valero Energy Corp	VLO	367.84	139.60	51,350.46		2.92%		29.50%	
Synopsys Inc	SNPS	152.30	386.25	58,826.65	0.21%			12.50%	0.03%
Etsy Inc	ETSY	124.65	111.33	13,877.17				24.50%	

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Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
CH Robinson Worldwide Inc	CHRW	114.89	99.37	11,416.52	0.04%	2.46%	0.00%	8.50%	0.00%
Accenture PLC	ACN	662.60	285.81	189,376.56	0.67%	1.57%	0.01%	12.50%	0.08%
TransDigm Group Inc	TDG	54.60	737.05	40,241.46	0.14%			20.00%	0.03%
Yum! Brands Inc	YUM	280.11	132.08	36,996.66	0.13%	1.83%	0.00%	10.50%	0.01%
Prologis Inc	PLD	923.45	124.77	115,218.86	0.41%	2.79%	0.01%	2.50%	0.01%
FirstEnergy Corp	FE	572.25	40.06	22,924.13	0.08%	3.89%	0.00%	3.00%	0.00%
VeriSign Inc	VRSN	104.88	211.33	22,164.08	0.08%			11.00%	0.01%
Quanta Services Inc	PWR	144.00	166.64	23,996.33	0.08%	0.19%	0.00%	15.50%	0.01%
Henry Schein Inc	HSIC	131.28	81.54	10,704.90	0.04%			6.00%	0.00%
Ameren Corp	AEE	262.48	86.39	22,675.22	0.08%	2.92%	0.00%	6.50%	0.01%
ANSYS Inc	ANSS	87.09	332.80	28,982.22	0.10%			8.50%	0.01%
FactSet Research Systems Inc	FDS	38.25	415.09	15,878.02	0.06%	0.86%	0.00%	10.50%	0.01%
NVIDIA Corp	NVDA	2,470.00	277.77	686,091.90		0.06%		23.00%	
Sealed Air Corp	SEE	143.96	45.91	6,609.30	0.02%	1.74%	0.00%	9.00%	0.00%
Cognizant Technology Solutions Corp	CTSH	509.30	60.93	31,031.34	0.11%	1.90%	0.00%	8.00%	0.01%
Intuitive Surgical Inc	ISRG	350.26	255.47	89,480.16	0.31%			10.00%	0.03%
Take-Two Interactive Software Inc	TTWO	168.68	119.30	20,122.93	0.07%			3.00%	0.00%
Republic Services Inc	RSG	316.24	135.22	42,762.51	0.15%	1.46%	0.00%	12.50%	0.02%
eBay Inc	EBAY	536.88	44.37	23,821.37	0.08%	2.25%	0.00%	12.50%	0.01%
Goldman Sachs Group Inc/The	GS	333.80	327.11	109,187.68	0.38%	3.06%	0.01%	5.00%	0.02%
SBA Communications Corp	SBAC	108.04	261.07	28,205.74		1.30%		35.50%	
Sempra Energy	SRE	314.65	151.16	47,562.49	0.17%	3.15%	0.01%	7.50%	0.01%
Moody's Corp	MCO	183.20	306.02	56,062.86	0.20%	1.01%	0.00%	4.00%	0.01%
ON Semiconductor Corp	ON	431.97	82.32	35,559.61	0.13%			18.50%	0.02%
Booking Holdings Inc	BKNG	37.65	2,652.41	99,857.93				22.00%	
F5 Inc	FFIV	55.07	145.69	8,023.44	0.03%			10.00%	0.00%
Akamai Technologies Inc	AKAM	156.30	78.30	12,238.60	0.04%			5.50%	0.00%
Charles River Laboratories International Inc	CRL	50.99	201.82	10,289.99	0.04%			12.00%	0.00%
MarketAxess Holdings Inc	MKTX	37.61	391.29	14,716.03	0.05%	0.74%	0.00%	10.00%	0.01%
Devon Energy Corp	DVN	654.00	50.61	33,098.94		7.03%		27.50%	
Bio-Techne Corp	TECH	157.28	74.19	11,668.23	0.04%	0.43%	0.00%	13.00%	0.01%
Alphabet Inc	GOOGL	5,956.00	103.73	617,815.88					
Teleflex Inc	TFX	46.94	253.31	11,891.38	0.04%	0.54%	0.00%	10.00%	0.00%
Bunge Ltd	BG	149.93	95.52	14,320.93	0.05%	2.62%	0.00%	2.50%	0.00%
Netflix Inc	NFLX	445.35	345.48	153,858.48	0.54%			14.50%	0.08%
Allegion plc	ALLE	87.87	106.73	9,378.04	0.03%	1.69%	0.00%	11.00%	0.00%
Agilent Technologies Inc	A	295.70	138.12	40,840.91	0.14%	0.65%	0.00%	12.00%	0.02%
Warner Bros Discovery Inc	WBD	2,435.60	15.10	36,777.56					
Elevance Health Inc	ELV	237.46	459.81	109,185.56	0.38%	1.29%	0.00%	12.50%	0.05%
Trimble Inc	TRMB	246.95	52.42	12,945.22	0.05%			7.00%	0.00%
CME Group Inc	CME	359.74	191.52	68,897.40	0.24%	2.30%	0.01%	8.50%	0.02%
Juniper Networks Inc	JNPR	321.34	34.42	11,060.66	0.04%	2.56%	0.00%	11.00%	0.00%
BlackRock Inc	BLK	150.24	669.12	100,525.91	0.35%	2.99%	0.01%	8.50%	0.03%
DTE Energy Co	DTE	206.11	109.54	22,577.07	0.08%	3.48%	0.00%	4.50%	0.00%
Nasdaq Inc	NDAQ	489.00	54.67	26,733.79	0.09%	1.46%	0.00%	8.50%	0.01%
Celanese Corp	CE	110.83	108.89	12,067.73	0.04%	2.57%	0.00%	7.50%	0.00%
Philip Morris International Inc	PM	1,552.15	97.25	150,946.39	0.53%	5.22%	0.03%	5.00%	0.03%
Salesforce Inc	CRM	1,000.00	199.78	199,780.00	0.70%			19.50%	0.14%
Ingersoll Rand Inc	IR	404.96	58.18	23,560.40		0.14%			
Huntington Ingalls Industries Inc	HII	39.93	207.02	8,265.48	0.03%	2.40%	0.00%	10.00%	0.00%
MetLife Inc	MET	774.36	57.94	44,866.53	0.16%	3.45%	0.01%	7.50%	0.01%
Tapestry Inc	TPR	236.08	43.11	10,177.24	0.04%	2.78%	0.00%	13.50%	0.00%
CSX Corp	CSX	2,048.43	29.94	61,330.05	0.22%	1.47%	0.00%	10.50%	0.02%
Edwards Lifesciences Corp	EW	606.10	82.73	50,142.65	0.18%			11.00%	0.02%
Ameriprise Financial Inc	AMP	105.15	306.50	32,227.86	0.11%	1.63%	0.00%	13.50%	0.02%
Zebra Technologies Corp	ZBRA	51.41	318.00	16,346.79	0.06%			11.50%	0.01%
Zimmer Biomet Holdings Inc	ZBH	210.06	129.20	27,140.27	0.10%	0.74%	0.00%	4.50%	0.00%
CBRE Group Inc	CBRE	309.89	72.81	22,563.24	0.08%			8.50%	0.01%
Camden Property Trust	CPT	106.76	104.84	11,193.03		3.82%		-4.00%	
Mastercard Inc	MA	945.72	363.41	343,685.20	1.21%	0.63%	0.01%	18.50%	0.22%
CarMax Inc	KMX	158.02	64.28	10,157.72				-3.00%	
Intercontinental Exchange Inc	ICE	558.85	104.29	58,282.57	0.20%	1.61%	0.00%	7.00%	0.01%
Fidelity National Information Services Inc	FIS	591.94	54.33	32,159.83		3.83%		52.00%	
Chipotle Mexican Grill Inc	CMG	27.62	1,708.29	47,186.39	0.17%			20.00%	0.03%
Wynn Resorts Ltd	WYNN	113.68	111.91	12,722.15				27.00%	
Live Nation Entertainment Inc	LYV	231.59	70.00	16,211.37					
Assurant Inc	AIZ	52.92	120.07	6,354.22	0.02%	2.33%	0.00%	15.50%	0.00%
NRG Energy Inc	NRG	232.27	34.29	7,964.54		4.40%		-2.50%	
Regions Financial Corp	RF	934.56	18.56	17,345.47	0.06%	4.31%	0.00%	11.50%	0.01%
Monster Beverage Corp	MNST	1,044.82	54.01	56,430.67	0.20%			10.50%	0.02%
Mosaic Co/The	MOS	336.49	45.88	15,438.02	0.05%	1.74%	0.00%	7.50%	0.00%
Baker Hughes Co	BKR	1,011.22	28.86	29,183.75		2.63%			
Expedia Group Inc	EXPE	147.83	97.03	14,343.46					
CF Industries Holdings Inc	CF	195.77	72.49	14,191.22	0.05%	2.21%	0.00%	11.00%	0.01%
Leidos Holdings Inc	LDOS	137.19	92.06	12,629.99	0.04%	1.56%	0.00%	8.00%	0.00%
APA Corp	APA	310.95	36.06	11,212.97		2.77%			
Alphabet Inc	GOOG	5,968.00	104.00	620,672.00	2.18%			18.50%	0.40%
First Solar Inc	FSLR	106.82	217.50	23,234.00				24.50%	
TE Connectivity Ltd	TEL	316.46	131.15	41,503.34	0.15%	1.80%	0.00%	10.50%	0.02%
Cooper Cos Inc/The	COO	49.46	373.36	18,464.89	0.06%	0.02%	0.00%	12.00%	0.01%
Discover Financial Services	DFS	259.36	98.84	25,635.24	0.09%	2.43%	0.00%	8.50%	0.01%
Linde PLC	LIN	490.77	355.44	174,438.22	0.61%	1.43%	0.01%	10.00%	0.06%
Visa Inc	V	1,624.95	225.46	366,362.13	1.29%	0.80%	0.01%	13.50%	0.17%
Mid-America Apartment Communities Inc	MAA	116.60	151.04	17,611.11		3.71%		-12.50%	
Xylem Inc/NY	XYL	180.28	104.70	18,875.11	0.07%	1.26%	0.00%	9.00%	0.01%
Marathon Petroleum Corp	MPC	441.63	134.83	59,544.43		2.23%			
Tractor Supply Co	TSCO	110.07	235.04	25,871.56	0.09%	1.75%	0.00%	13.50%	0.01%
Advanced Micro Devices Inc	AMD	1,611.39	98.01	157,932.14				25.50%	
ResMed Inc	RMD	146.91	218.99	32,171.60	0.11%	0.80%	0.00%	8.50%	0.01%
Mettler-Toledo International Inc	MTD	22.07	1,530.21	33,771.73	0.12%			13.50%	0.02%

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Jacobs Solutions Inc	J	126.71	117.51	14,890.16	0.05%	0.89%	0.00%	12.00%	0.01%
Copart Inc	CPRT	476.59	75.21	35,844.56	0.13%			7.00%	0.01%
VICI Properties Inc	VICI	1,004.21	32.62	32,757.17	0.12%	4.78%	0.01%	7.00%	0.01%
Albemarle Corp	ALB	117.30	221.04	25,927.77		0.72%		21.50%	
Fortinet Inc	FTNT	784.07	66.46	52,109.03				21.50%	
Moderna Inc	MRNA	385.68	153.58	59,232.43				-2.50%	
Essex Property Trust Inc	ESS	64.46	209.14	13,482.00		4.42%		-3.00%	
CoStar Group Inc	CSGP	406.77	68.85	28,006.25	0.10%			13.00%	0.01%
Realty Income Corp	O	660.52	63.32	41,824.19	0.15%	4.83%	0.01%	5.50%	0.01%
Westrock Co	WRK	254.65	30.47	7,759.25	0.03%	3.61%	0.00%	10.00%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	180.35	101.06	18,226.37	0.06%	0.67%	0.00%	9.50%	0.01%
Pool Corp	POOL	39.10	342.44	13,389.75	0.05%	1.17%	0.00%	14.00%	0.01%
Western Digital Corp	WDC	319.32	37.67	12,028.86	0.04%			4.00%	0.00%
PepsiCo Inc	PEP	1,377.32	182.30	251,084.52	0.88%	2.52%	0.02%	6.50%	0.06%
Diamondback Energy Inc	FANG	183.59	135.17	24,815.86		8.73%			
ServiceNow Inc	NOW	203.00	464.72	94,338.16				45.50%	
Church & Dwight Co Inc	CHD	244.04	88.41	21,575.66	0.08%	1.23%	0.00%	6.00%	0.00%
Federal Realty Investment Trust	FRT	81.35	98.83	8,040.12	0.03%	4.37%	0.00%	2.50%	0.00%
MGM Resorts International	MGM	372.89	44.42	16,563.86				25.00%	
American Electric Power Co Inc	AEP	514.41	90.99	46,805.89	0.16%	3.65%	0.01%	6.00%	0.01%
SolarEdge Technologies Inc	SEDG	56.15	303.95	17,065.88				27.00%	
Invitation Homes Inc	INVH	611.41	31.23	19,094.37		3.33%			
PTC Inc	PTC	118.26	128.23	15,164.86				29.00%	
JB Hunt Transport Services Inc	JBHT	103.77	175.46	18,207.48	0.06%	0.96%	0.00%	10.00%	0.01%
Lam Research Corp	LRCX	134.94	530.12	71,532.27	0.25%	1.30%	0.00%	14.00%	0.04%
Mohawk Industries Inc	MHK	63.54	100.22	6,367.98	0.02%			10.00%	0.00%
GE HealthCare Technologies Inc	GEHC	453.93	82.03	37,235.55					
Pentair PLC	PNR	164.94	55.27	9,116.23	0.03%	1.59%	0.00%	12.00%	0.00%
Vertex Pharmaceuticals Inc	VRTX	257.09	315.07	81,001.66	0.28%			13.50%	0.04%
Amcor PLC	AMCR	1,485.78	11.38	16,908.18	0.06%	4.31%	0.00%	14.50%	0.01%
Meta Platforms Inc	META	2,225.76	211.94	471,728.21	1.66%			11.00%	0.18%
T-Mobile US Inc	TMUS	1,219.38	144.84	176,615.43	0.62%			16.00%	0.10%
United Rentals Inc	URI	69.36	395.76	27,449.91	0.10%	1.50%	0.00%	18.00%	0.02%
Honeywell International Inc	HON	668.14	191.12	127,694.92	0.45%	2.16%	0.01%	12.00%	0.05%
Alexandria Real Estate Equities Inc	ARE	173.09	125.59	21,738.00	0.08%	3.85%	0.00%	11.00%	0.01%
Delta Air Lines Inc	DAL	641.24	34.92	22,392.07					
Seagate Technology Holdings PLC	STX	206.48	66.12	13,652.72	0.05%	4.23%	0.00%	12.00%	0.01%
United Airlines Holdings Inc	UAL	326.73	44.25	14,457.76					
News Corp	NWS	193.24	17.43	3,368.23		1.15%			
Centene Corp	CNC	550.70	63.21	34,809.75	0.12%			9.00%	0.01%
Martin Marietta Materials Inc	MLM	62.10	355.06	22,050.65	0.08%	0.74%	0.00%	4.50%	0.00%
Teradyne Inc	TER	156.05	107.51	16,776.72	0.06%	0.41%	0.00%	19.00%	0.01%
PayPal Holdings Inc	PYPL	1,131.37	75.94	85,916.47	0.30%			12.00%	0.04%
Tesla Inc	TSLA	3,164.10	207.46	656,424.81				21.50%	
Arch Capital Group Ltd	ACGL	371.20	67.87	25,193.14				21.50%	
DISH Network Corp	DISH	292.72	9.33	2,731.05				-4.00%	
Dow Inc	DOW	707.99	54.82	38,811.96	0.14%	5.11%	0.01%	8.50%	0.01%
Everest Re Group Ltd	RE	39.16	358.02	14,018.99	0.05%	1.84%	0.00%	9.50%	0.00%
Teledyne Technologies Inc	TDY	47.00	447.36	21,023.68	0.07%			9.50%	0.01%
News Corp	NWSA	382.36	17.27	6,603.41		1.16%			
Exelon Corp	EXC	994.30	41.89	41,651.19		3.44%			
Global Payments Inc	GPN	263.78	105.24	27,760.63	0.10%	0.95%	0.00%	17.00%	0.02%
Crown Castle Inc	CCI	433.67	133.84	58,042.26	0.20%	4.68%	0.01%	13.50%	0.03%
Aptiv PLC	APTV	270.95	112.19	30,397.88				30.00%	
Advance Auto Parts Inc	AAP	59.27	121.61	7,208.31	0.03%	4.93%	0.00%	12.00%	0.00%
Align Technology Inc	ALGN	76.74	334.14	25,641.57	0.09%			17.00%	0.02%
Illumina Inc	ILMN	158.00	232.55	36,742.90	0.13%			6.50%	0.01%
Targa Resources Corp	TRGP	226.28	72.95	16,506.83		1.92%			
LKQ Corp	LKQ	267.29	56.76	15,171.38	0.05%	1.94%	0.00%	13.00%	0.01%
Zoetis Inc	ZTS	462.95	166.44	77,052.57	0.27%	0.90%	0.00%	9.00%	0.02%
Equinix Inc	EQIX	92.75	721.04	66,872.85	0.24%	1.89%	0.00%	15.00%	0.04%
Digital Realty Trust Inc	DLR	291.30	98.31	28,637.31		4.96%		-1.00%	
Molina Healthcare Inc	MOH	58.27	267.49	15,586.37	0.05%			12.50%	0.01%
Las Vegas Sands Corp	LVS	764.27	57.45	43,907.48					

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of March 31, 2023
[5] Source: Bloomberg Professional as of March 31, 2023
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of March 31, 2023
[9] Equals [7] x [8]
[10] Source: Value Line, as of March 31, 2023
[11] Equals [7] x [10]

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BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12 38%	7.81%	4.58%
1992 2	11 83%	7.90%	3.93%
1992 3	12 03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11 84%	7.07%	4.76%
1993 2	11 64%	6.86%	4.78%
1993 3	11.15%	6.32%	4.84%
1993.4	11 04%	6.14%	4.91%
1994.1	11 07%	6.58%	4.49%
1994 2	11.13%	7.36%	3.77%
1994 3	12.75%	7.59%	5.16%
1994.4	11 24%	7.96%	3.28%
1995.1	11 96%	7.63%	4.33%
1995 2	11 32%	6.94%	4.37%
1995 3	11 37%	6.72%	4.65%
1995.4	11 58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996 2	11.46%	6.92%	4.54%
1996 3	10.70%	6.97%	3.73%
1996.4	11 56%	6.62%	4.94%
1997.1	11 08%	6.82%	4.26%
1997 2	11 62%	6.94%	4.68%
1997 3	12 00%	6.53%	5.47%
1997.4	11 06%	6.15%	4.91%
1998.1	11 31%	5.88%	5.43%
1998 2	12 20%	5.85%	6.35%
1998 3	11 65%	5.48%	6.17%
1998.4	12 30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999 2	10 94%	5.80%	5.14%
1999 3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11 21%	6.30%	4.92%
2000 2	11 00%	5.98%	5.02%
2000 3	11 68%	5.79%	5.89%
2000.4	12 50%	5.69%	6.81%
2001.1	11 38%	5.45%	5.93%
2001 2	11 00%	5.70%	5.30%
2001 3	10.76%	5.53%	5.23%
2001.4	11 99%	5.30%	6.69%
2002.1	10 05%	5.52%	4.53%
2002 2	11.41%	5.62%	5.79%
2002 3	11 65%	5.09%	6.56%
2002.4	11 57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003 2	11.16%	4.60%	6.56%
2003 3	10 50%	5.11%	5.39%
2003.4	11 34%	5.11%	6.23%
2004.1	11 00%	4.88%	6.12%
2004 2	10 64%	5.34%	5.30%
2004 3	10.75%	5.11%	5.64%
2004.4	11 24%	4.93%	6.31%
2005.1	10 63%	4.71%	5.92%
2005 2	10 31%	4.47%	5.84%
2005 3	11 08%	4.42%	6.66%
2005.4	10 63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006 2	10.79%	5.14%	5.64%
2006 3	10 35%	5.00%	5.35%
2006.4	10 65%	4.74%	5.91%
2007.1	10 59%	4.80%	5.79%
2007 2	10 33%	4.99%	5.34%
2007 3	10.40%	4.95%	5.45%
2007.4	10 65%	4.61%	6.04%
2008.1	10 62%	4.41%	6.21%
2008 2	10 54%	4.57%	5.96%
2008 3	10.43%	4.45%	5.98%

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BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
Quarter	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2008.4	10.39%	3 64%	6.74%
2009.1	10.75%	3.44%	7 31%
2009.2	10.75%	4.17%	6 58%
2009.3	10.50%	4 32%	6.18%
2009.4	10.59%	4 34%	6 25%
2010.1	10.59%	4 62%	5 97%
2010.2	10.18%	4 37%	5 81%
2010.3	10.40%	3 86%	6 55%
2010.4	10.38%	4.17%	6 20%
2011.1	10.09%	4 56%	5 53%
2011.2	10.26%	4 34%	5 92%
2011.3	10.57%	3.70%	6 88%
2011.4	10.39%	3 04%	7 35%
2012.1	10.30%	3.14%	7.17%
2012.2	9 95%	2 94%	7 01%
2012.3	9 90%	2.74%	7.16%
2012.4	10.16%	2 86%	7 30%
2013.1	9 85%	3.13%	6.72%
2013.2	9 86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9 97%	3.79%	6.18%
2014.1	9 86%	3 69%	6.16%
2014.2	10.10%	3.44%	6 66%
2014.3	9 90%	3 27%	6 63%
2014.4	9 94%	2 96%	6 98%
2015.1	9 64%	2 55%	7 08%
2015.2	9 83%	2 88%	6 94%
2015.3	9.40%	2 96%	6.44%
2015.4	9 86%	2 96%	6 90%
2016.1	9.70%	2.72%	6 98%
2016.2	9.48%	2 57%	6 91%
2016.3	9.74%	2 28%	7.46%
2016.4	9 83%	2 83%	7 00%
2017.1	9.72%	3 05%	6 67%
2017.2	9 64%	2 90%	6.75%
2017.3	10.00%	2 82%	7.18%
2017.4	9 91%	2 82%	7 09%
2018.1	9 69%	3 02%	6 66%
2018.2	9.75%	3 09%	6 66%
2018.3	9 69%	3 06%	6 63%
2018.4	9 52%	3 27%	6 25%
2019.1	9.72%	3 01%	6.70%
2019.2	9 58%	2.78%	6.79%
2019.3	9 53%	2 29%	7 25%
2019.4	9 89%	2 26%	7 63%
2020.1	9.72%	1 89%	7 83%
2020.2	9 58%	1 38%	8.19%
2020.3	9 30%	1 37%	7 93%
2020.4	9 56%	1 62%	7 94%
2021.1	9.45%	2 07%	7 38%
2021.2	9.47%	2 26%	7 21%
2021.3	9 27%	1 93%	7 34%
2021.4	9 67%	1 95%	7.73%
2022.1	9.45%	2 25%	7 20%
2022.2	9 50%	3 05%	6.45%
2022.3	9.14%	3 26%	5 88%
2022.4	9 87%	3 89%	5 98%
2023.1	9 68%	3.74%	5 94%
AVERAGE	10.60%	4 55%	6 05%
MEDIAN	10.57%	4 60%	6.17%

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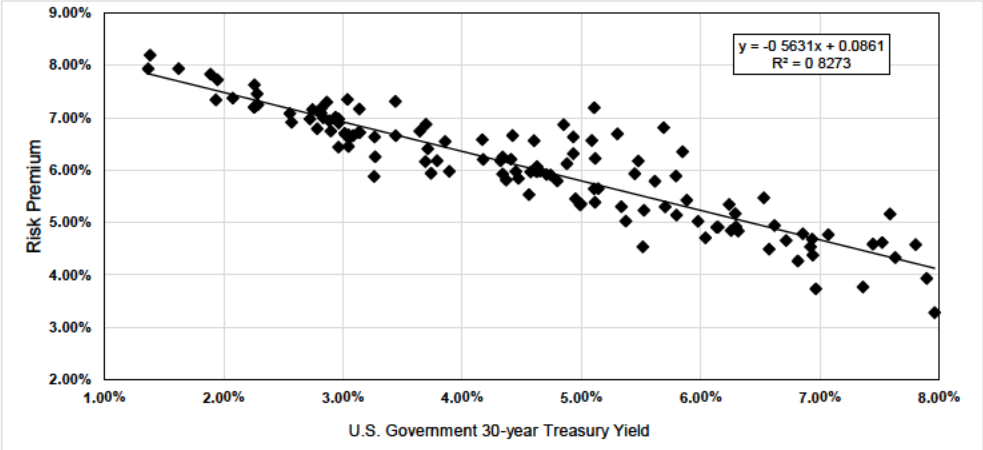

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.909557
R Square	0.827294
Adjusted R Square	0.825890
Standard Error	0.004270
Observations	125

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010745	0.010745	589.193673	0.000000
Residual	123	0.002243	0.000018		
Total	124	0.012988			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0 0861	0.0011	76.73	0.00000	0.08389	0.08833	0 08389	0.08833
US Government 30-year Treasury	(0 5631)	0.0232	(24.27)	0.00000	(0.60901)	(0.51717)	(0.60901)	(0.51717)

	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	3.81%	6.47%	10.27%
Blue Chip Near-Term Projected Forecast (Q2 2023 - Q2 2024) [5]	3.88%	6.43%	10.31%
Blue Chip Long-Term Projected Forecast (2024-2028) [6]	3.90%	6.41%	10.31%
AVERAGE			10.30%

Notes:
[1] Source: Regulatory Research Associates, rate cases through March 31,2023
[2] Source: S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] – Column [2]
[4] Source: S&P Capital IQ Pro, 30-day average as of February 28, 2023
[5] Blue Chip Financial Forecasts, Vol. 42, No. 3, March 1, 2023, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 41, No. 12, December 2, 2022, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0 086108 + (-0 563088 x Column [7])
[9] Equals Column [7] + Column [8]

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EVERGY METRO - PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2023	2024	2025	2026	2027	2023-27 Cap. Ex. / 2022 Net Plant
ALLETE, Inc.	ALE							
Capital Spending per Share			$5.95	$6 60	$7.25	$7.25	$7 25	
Common Shares Outstanding			58.00	59 50	61.00	61.00	61 00	
Capital Expenditures			$345.1	$392.7	$442 3	$442.3	$442 3	39.59%
Net Plant		$5,215 0						
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.90	$6 08	$6.25	$6.25	$6 25	
Common Shares Outstanding			251.50	252 25	253.00	253.00	253 00	
Capital Expenditures			$1,483.9	$1,532.4	$1,581 3	$1,581.3	$1,581 3	48.42%
Net Plant		$16,025 0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.55	$12.78	$13.00	$13.00	$13 00	
Common Shares Outstanding			267.00	273 50	280.00	280.00	280 00	
Capital Expenditures			$3,350.9	$3,494.0	$3,640 0	$3,640.0	$3,640 0	56.89%
Net Plant		$31,225 0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$14.15	$14 08	$14.00	$14.00	$14 00	
Common Shares Outstanding			523.00	534 00	545.00	545.00	545 00	
Capital Expenditures			$7,400.5	$7,516.1	$7,630 0	$7,630.0	$7,630 0	53.51%
Net Plant		$70,650 0						
Avista Corporation	AVA							
Capital Spending per Share			$6.40	$6 20	$6.00	$6.00	$6 00	
Common Shares Outstanding			77.00	80 00	83.00	83.00	83 00	
Capital Expenditures			$492.8	$496.0	$498 0	$498.0	$498 0	45.56%
Net Plant		$5,450 0						
CMS Energy Corporation	CMS							
Capital Spending per Share			$10.00	$9 88	$9.75	$9.75	$9.75	
Common Shares Outstanding			290.00	295 00	300.00	300.00	300 00	
Capital Expenditures			$2,900.0	$2,913.1	$2,925 0	$2,925.0	$2,925 0	61.36%
Net Plant		$23,775 0						
Duke Energy Corporation	DUK							
Capital Spending per Share			$16.75	$16.75	$16.75	$16.75	$16.75	
Common Shares Outstanding			770.00	770 00	770.00	770.00	770 00	
Capital Expenditures			$12,897.5	$12,897.5	$12,897 5	$12,897.5	$12,897 5	54.78%
Net Plant		$117,725 0						
Entergy Corporation	ETR							
Capital Spending per Share			$19.00	$19 38	$19.75	$19.75	$19.75	
Common Shares Outstanding			209.00	211 50	214.00	214.00	214 00	
Capital Expenditures			$3,971.0	$4,097.8	$4,226 5	$4,226.5	$4,226 5	47.42%
Net Plant		$43,750 0						
DACORP, Inc.	IDA							
Capital Spending per Share			$14.20	$12.15	$10.10	$10.10	$10.10	
Common Shares Outstanding			51.00	51 50	52.00	52.00	52 00	
Capital Expenditures			$724.2	$625.7	$525 2	$525.2	$525 2	55.72%
Net Plant		$5,250 0						

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EVERGY METRO - PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2023	2024	2025	2026	2027	2023-27 Cap. Ex. / 2022 Net Plant
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$8.40	$9 20	$10.00	$10.00	$10 00	
Common Shares Outstanding			2025.00	2025 00	2025.00	2025.00	2025 00	
Capital Expenditures			$17,010.0	$18,630.0	$20,250 0	$20,250.0	$20,250 0	86.90%
Net Plant		$110,925 0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$9.10	$7 80	$6.50	$6.50	$6 50	
Common Shares Outstanding			62.00	62 00	62.00	62.00	62 00	
Capital Expenditures			$564.2	$483.6	$403 0	$403.0	$403 0	40.09%
Net Plant		$5,630 0						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75	$4.75	
Common Shares Outstanding			200.20	200 20	200.20	200.20	200 20	
Capital Expenditures			$951.0	$951.0	$951 0	$951.0	$951 0	45.96%
Net Plant		$10,345 0						
Otter Tail Corporation	OTTR							
Capital Spending per Share			$5.90	$6 08	$6.25	$6.25	$6 25	
Common Shares Outstanding			41.90	42 20	42.50	42.50	42 50	
Capital Expenditures			$247.2	$256.4	$265 6	$265.6	$265 6	58.84%
Net Plant		$2,210 0						
Portland General Electric Company	POR							
Capital Spending per Share			$8.25	$8 38	$8.50	$8.50	$8 50	
Common Shares Outstanding			94.50	97 25	100.00	100.00	100 00	
Capital Expenditures			$779.6	$814.5	$850 0	$850.0	$850 0	49.78%
Net Plant		$8,325 0						
Southern Company	SO							
Capital Spending per Share			$7.85	$7 68	$7.50	$7.50	$7 50	
Common Shares Outstanding			1070.00	1070 00	1070.00	1070.00	1070 00	
Capital Expenditures			$8,399.5	$8,212.3	$8,025 0	$8,025.0	$8,025 0	42.76%
Net Plant		$95,150 0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$9.00	$9 00	$9.00	$9.00	$9 00	
Common Shares Outstanding			550.00	555 50	561.00	561.00	561 00	
Capital Expenditures			$4,950.0	$4,999.5	$5,049 0	$5,049.0	$5,049 0	52.04%
Net Plant		$48,225 0						
Evergy Metro	Evergy Metro							
Capital Expenditures [8]			$305.61	$305 61	$305.61	$305 61	$305 61	46.73%
Net Plant [9]		$3,269 9						

Notes:
[1] - [6] Source: Value Line, dated November 11, 2022, December 9, 2022, January 20, 2023.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Provided by the Companies
[9] Provided by the Companies

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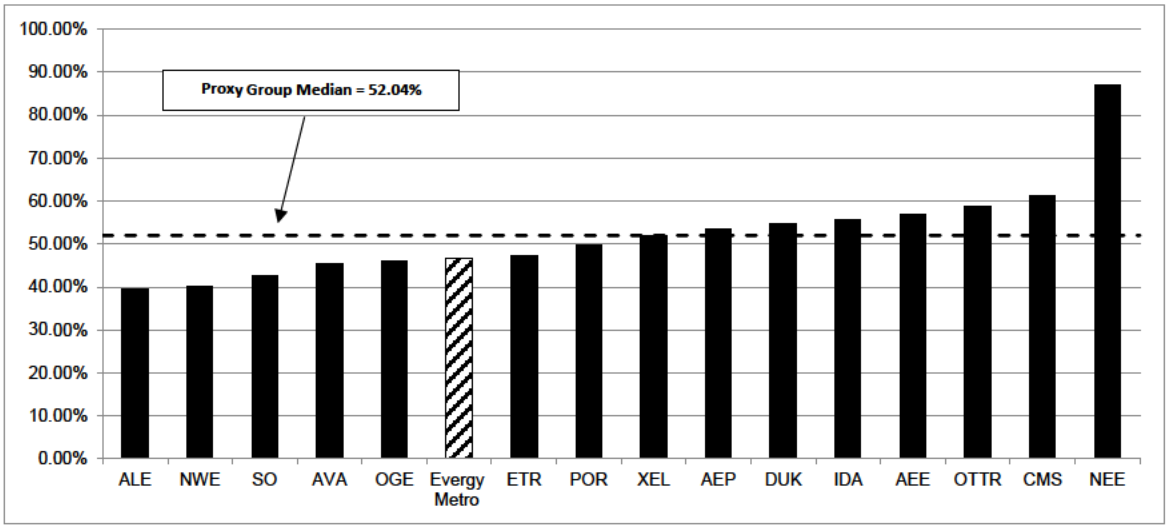
EVERGY METRO - PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT



	Company	Ticker	Projected CAPEX / 2022 Net Plant [1]
1	ALLETE, Inc.	ALE	39.59%
2	NorthWestern Corporation	NWE	40.09%
3	Southern Company	SO	42.76%
4	Avista Corporation	AVA	45.56%
5	OGE Energy Corporation	OGE	45.96%
6	Evergy Metro	Evergy Metro	46.73%
7	Entergy Corporation	ETR	47.42%
9	Portland General Electric Company	POR	49.78%
10	Xcel Energy Inc.	XEL	52.04%
11	American Electric Power Company, Inc.	AEP	53.51%
12	Duke Energy Corporation	DUK	54.78%
13	IDACORP, Inc.	IDA	55.72%
14	Ameren Corporation	AEE	56.89%
15	Otter Tail Corporation	OTTR	58.84%
16	CMS Energy Corporation	CMS	61.36%
17	NextEra Energy, Inc.	NEE	86.90%
	Proxy Group Median		52.04%
	The Companies as % of the Median		0.90

Notes:
[1] Exhibit No. AEB-8, pgs. 1-2, col. [7]

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EVERGY CENTRAL - PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2023	2024	2025	2026	2027	2023-27 Cap. Ex. / 2022 Net Plant
ALLETE, Inc.	ALE							
Capital Spending per Share			$5.95	$6 60	$7.25	$7.25	$7 25	
Common Shares Outstanding			58.00	59 50	61.00	61.00	61 00	
Capital Expenditures			$345.1	$392.7	$442 3	$442.3	$442 3	39.59%
Net Plant		$5,215 0						
Alliant Energy Corporation	LNT							
Capital Spending per Share			$5.90	$6 08	$6.25	$6.25	$6 25	
Common Shares Outstanding			251.50	252 25	253.00	253.00	253 00	
Capital Expenditures			$1,483.9	$1,532.4	$1,581 3	$1,581.3	$1,581 3	48.42%
Net Plant		$16,025 0						
Ameren Corporation	AEE							
Capital Spending per Share			$12.55	$12.78	$13.00	$13.00	$13 00	
Common Shares Outstanding			267.00	273 50	280.00	280.00	280 00	
Capital Expenditures			$3,350.9	$3,494.0	$3,640 0	$3,640.0	$3,640 0	56.89%
Net Plant		$31,225 0						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$14.15	$14 08	$14.00	$14.00	$14 00	
Common Shares Outstanding			523.00	534 00	545.00	545.00	545 00	
Capital Expenditures			$7,400.5	$7,516.1	$7,630 0	$7,630.0	$7,630 0	53.51%
Net Plant		$70,650 0						
Avista Corporation	AVA							
Capital Spending per Share			$6.40	$6 20	$6.00	$6.00	$6 00	
Common Shares Outstanding			77.00	80 00	83.00	83.00	83 00	
Capital Expenditures			$492.8	$496.0	$498 0	$498.0	$498 0	45.56%
Net Plant		$5,450 0						
CMS Energy Corporation	CMS							
Capital Spending per Share			$10.00	$9 88	$9.75	$9.75	$9.75	
Common Shares Outstanding			290.00	295 00	300.00	300.00	300 00	
Capital Expenditures			$2,900.0	$2,913.1	$2,925 0	$2,925.0	$2,925 0	61.36%
Net Plant		$23,775 0						
Duke Energy Corporation	DUK							
Capital Spending per Share			$16.75	$16.75	$16.75	$16.75	$16.75	
Common Shares Outstanding			770.00	770 00	770.00	770.00	770 00	
Capital Expenditures			$12,897.5	$12,897.5	$12,897 5	$12,897.5	$12,897 5	54.78%
Net Plant		$117,725 0						
Entergy Corporation	ETR							
Capital Spending per Share			$19.00	$19 38	$19.75	$19.75	$19.75	
Common Shares Outstanding			209.00	211 50	214.00	214.00	214 00	
Capital Expenditures			$3,971.0	$4,097.8	$4,226 5	$4,226.5	$4,226 5	47.42%
Net Plant		$43,750 0						
DACORP, Inc.	IDA							
Capital Spending per Share			$14.20	$12.15	$10.10	$10.10	$10.10	
Common Shares Outstanding			51.00	51 50	52.00	52.00	52 00	
Capital Expenditures			$724.2	$625.7	$525 2	$525.2	$525 2	55.72%
Net Plant		$5,250 0						

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EVERGY CENTRAL - PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2022	2023	2024	2025	2026	2027	2023-27 Cap. Ex. / 2022 Net Plant
NextEra Energy, Inc.	NEE							
Capital Spending per Share			$8.40	$9 20	$10.00	$10.00	$10 00	
Common Shares Outstanding			2025.00	2025 00	2025.00	2025.00	2025 00	
Capital Expenditures			$17,010.0	$18,630.0	$20,250 0	$20,250.0	$20,250 0	86.90%
Net Plant		$110,925 0						
NorthWestern Corporation	NWE							
Capital Spending per Share			$9.10	$7 80	$6.50	$6.50	$6 50	
Common Shares Outstanding			62.00	62 00	62.00	62.00	62 00	
Capital Expenditures			$564.2	$483.6	$403 0	$403.0	$403 0	40.09%
Net Plant		$5,630 0						
OGE Energy Corporation	OGE							
Capital Spending per Share			$4.75	$4.75	$4.75	$4.75	$4.75	
Common Shares Outstanding			200.20	200 20	200.20	200.20	200 20	
Capital Expenditures			$951.0	$951.0	$951 0	$951.0	$951 0	45.96%
Net Plant		$10,345 0						
Otter Tail Corporation	OTTR							
Capital Spending per Share			$5.90	$6 08	$6.25	$6.25	$6 25	
Common Shares Outstanding			41.90	42 20	42.50	42.50	42 50	
Capital Expenditures			$247.2	$256.4	$265 6	$265.6	$265 6	58.84%
Net Plant		$2,210 0						
Portland General Electric Company	POR							
Capital Spending per Share			$8.25	$8 38	$8.50	$8.50	$8 50	
Common Shares Outstanding			94.50	97 25	100.00	100.00	100 00	
Capital Expenditures			$779.6	$814.5	$850 0	$850.0	$850 0	49.78%
Net Plant		$8,325 0						
Southern Company	SO							
Capital Spending per Share			$7.85	$7 68	$7.50	$7.50	$7 50	
Common Shares Outstanding			1070.00	1070 00	1070.00	1070.00	1070 00	
Capital Expenditures			$8,399.5	$8,212.3	$8,025 0	$8,025.0	$8,025 0	42.76%
Net Plant		$95,150 0						
Xcel Energy Inc.	XEL							
Capital Spending per Share			$9.00	$9 00	$9.00	$9.00	$9 00	
Common Shares Outstanding			550.00	555 50	561.00	561.00	561 00	
Capital Expenditures			$4,950.0	$4,999.5	$5,049 0	$5,049.0	$5,049 0	52.04%
Net Plant		$48,225 0						
Evergy Central	Evergy Central							
Capital Expenditures [8]			$1,215 36	$1,215.36	$1,215 36	$1,215.36	$1,215 36	63.87%
Net Plant [9]		$9,514 3						

Notes:
[1] - [6] Source: Value Line, dated November 11, 2022, December 9, 2022, January 20, 2023.
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Provided by the Companies
[9] Provided by the Companies

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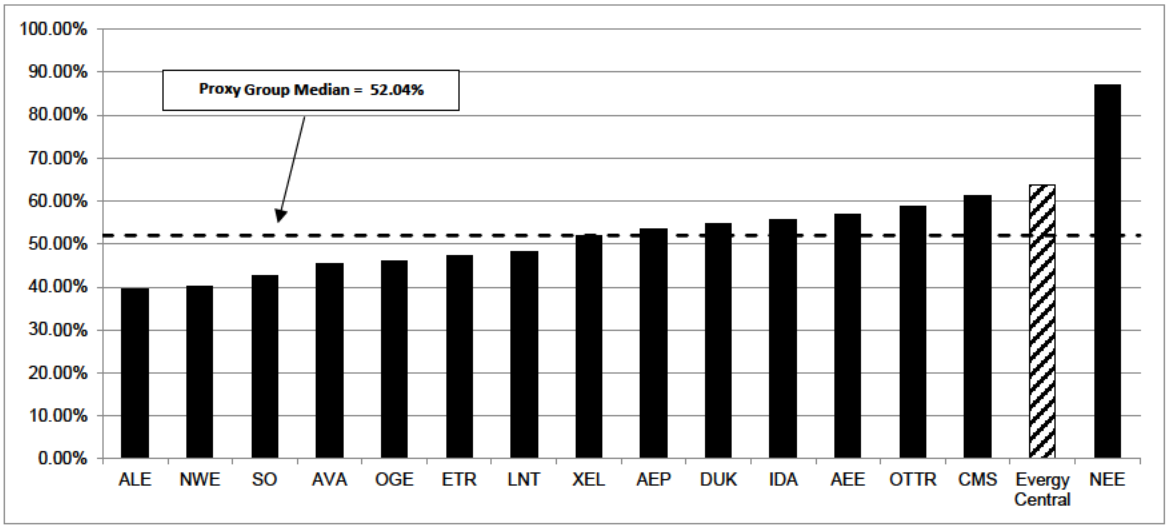
EVERGY CENTRAL - PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF NET PLANT



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5	OGE Energy Corporation	OGE	45.96%
6	Entergy Corporation	ETR	47.42%
7	Alliant Energy Corporation	LNT	48.42%
9	Xcel Energy Inc.	XEL	52.04%
10	American Electric Power Company, Inc.	AEP	53.51%
11	Duke Energy Corporation	DUK	54.78%
12	IDACORP, Inc.	IDA	55.72%
13	Ameren Corporation	AEE	56.89%
14	Otter Tail Corporation	OTTR	58.84%
15	CMS Energy Corporation	CMS	61.36%
16	Evergy Central	Evergy Central	63.87%
17	NextEra Energy, Inc.	NEE	86.90%
	Proxy Group Median		52.04%
	The Companies as % of the Median		1.23

Notes:
[1] Exhibit No. AEB-8, p. 3-4, col. [7]

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REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
					Revenue Stabilization				Capital Cost Recovery		
Company	Operating Subsidiary	State	Utility Type	Test Year Convention	Revenue Decoupling	Formula-Based Rates	Straight Fixed Variable Rate Design	Overall Revenue Stabilization	Capital Cost Recovery Mechanism	CWIP In Rate Base/ Equivalent	Overall Capital Cost Recovery
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Fully Forecast	No	No	No	No	Yes	Yes	Yes
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Historical	No	No	No	No	No	No	No
	Interstate Power & Light Co.	Iowa	Gas	Historical	No	No	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	Yes	Yes
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	Yes	Yes
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Historical	No	Yes	No	Yes	No	Yes	Yes
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Yes	No	No	Yes	Yes	No	Yes
	Union Electric Co.	Missouri	Gas	Historical	Yes	No	No	Yes	Yes	No	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Yes	Yes	No	Yes	Yes	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Yes	No	No	Yes	Yes	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	No	No	No
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Yes	Yes	No	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	No	No	No	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Fully Forecast	No	No	No	No	No	No	No
	AEP Texas	Texas	Electric	Historical	No	No	No	No	Yes	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	Yes	No	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	Yes	Yes	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	No	No	No
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Historical	No	No	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Historical	Yes	No	No	Yes	No	Yes	Yes
	Avista Corp.	Idaho	Gas	Historical	Yes	No	No	Yes	No	Yes	Yes
	Avista Corp.	Oregon	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No
	Avista Corp.	Washington	Electric	Historical	Yes	No	No	Yes	No	Yes	Yes
	Avista Corp.	Washington	Gas	Historical	Yes	No	No	Yes	No	Yes	Yes
CMS	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No	No	Yes	No
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Yes	No	No	Yes	No	Yes	No
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Historical	Yes	No	No	Yes	Yes	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Yes	No	No	Yes	No	No	No
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Yes	No	No	Yes	No	No	No
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Historical	No	No	No	No	No	Yes	Yes
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Yes	No	No	Yes	Yes	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Yes	No	No	Yes	Yes	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Historical	No	No	No	No	No	Yes	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	Yes	No	No	Yes	No	Yes	Yes
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Fully Forecast	Yes	No	No	Yes	Yes	No	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Yes	Yes	No	Yes	Yes	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	Yes	Yes	No	Yes	Yes	No	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	No	No	No
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Yes	Yes	No	Yes	Yes	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	Yes	Yes	No	Yes	Yes	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	No	Yes	Yes
	Entergy Texas Inc.	Texas	Electric	Historical	No	No	No	No	Yes	No	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Yes	No	No	Yes	No	Yes	Yes
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Gulf Power Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Lone Star Transmission LLC	Texas	Electric	Historical	No	No	No	No	Yes	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	Yes	No	No	Yes	No	No	No
	NorthWestern Corporation	Montana	Gas	Historical	No	No	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Historical	No	No	No	No	No	Yes	Yes
	NorthWestern Corporation	South Dakota	Electric	Historical	No	No	No	No	No	Yes	Yes
	NorthWestern Corporation	South Dakota	Gas	Historical	No	No	No	No	No	Yes	Yes

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REGULATORY RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
					Revenue Stabilization				Capital Cost Recovery		
Company	Operating Subsidiary	State	Utility Type	Test Year Convention	Revenue Decoupling	Formula-Based Rates	Straight Fixed Variable Rate Design	Overall Revenue Stabilization	Capital Cost Recovery Mechanism	CWIP In Rate Base/ Equivalent	Overall Capital Cost Recovery
OGE Energy Corporation	Oklahoma Gas and Electric Co.	Arkansas	Electric	Historical	Yes	Yes	No	Yes	No	Yes	Yes
	Oklahoma Gas & Electric Co.	Oklahoma	Electric	Historical	Yes	No	No	Yes	Yes	Yes	Yes
Otter Tail Corporation	Otter Tail Power Co.	Minnesota	Electric	Fully Forecast	No	No	No	No	No	Yes	Yes
	Otter Tail Power Co.	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Otter Tail Power Co.	South Dakota	Electric	Historical	No	No	No	No	Yes	Yes	Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Fully Forecast	Yes	No	No	Yes	Yes	No	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Fully Forecast	No	Yes	No	Yes	Yes	No	Yes
	Georgia Power Co.	Georgia	Electric	Fully Forecast	No	Yes	No	Yes	Yes	Yes	Yes
	Atlanta Gas & Light Co.	Georgia	Gas	Fully Forecast	No	Yes	Yes	Yes	Yes	Yes	Yes
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Yes	No	No	Yes	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Yes	Yes	No	Yes	No	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Fully Forecast	Yes	Yes	No	Yes	No	No	No
	Virginia Natural Gas Inc.	Virginia	Gas	Historical	Yes	No	No	Yes	Yes	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Yes	No	No	Yes	Yes	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Yes	No	No	Yes	Yes	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Yes	Yes	No	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Historical	No	No	No	No	No	No	No
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	Yes	Yes	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Yes	No	No	Yes	Yes	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	Yes	No	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	Yes	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	Yes	Yes
Proxy Group Average			Fully Forecast	35				Yes 47			65
			Partially Forecast	7				No 35			17
			Historical	40							
			Forecast	51.22%				% Yes 57.3%			79.3%
Evergy, Inc.	Evergy Metro [9]	Kansas	Electric	Historical	No	No	No	No	Yes		Yes
Evergy, Inc.	Evergy Central [9]	Kansas	Electric	Historical	Yes	No	No	Yes	Yes		Yes

Notes
[1] Regulatory Research Associates, effective as of December 31, 2022
[2] S&P Global Market Intelligence, Regulatory Focus Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit. A designation of "Yes" indicates full or partial decoupling.
[3] - [4] Form 10-K; company tariffs; S&P Global Market Intelligence
[5] If either [2], [3], or [4] equals "No", then "No"; if not, then "Yes"
[6] S&P Global Market Intelligence, Regulatory Focus Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit. A designation of "Yes" indicates full or partial decoupling.
[7] S&P Capital IQ Pro
[8] If [7] of [8] equals "Yes", then "Yes"; if not, then "No"
[9] Data provided by the Companies

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COMPARISON OF EVERGY METRO / EVERGY KANSAS CITY AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
		Rank	Numeric Rank
ALLETE Inc.	Minnesota	Average / 2	5
	North Dakota	Average / 1	4
Alliant Energy Corporation	Iowa	Above Average / 3	3
	Minnesota	Average / 2	5
	Wisconsin	Above Average / 3	3
Ameren Corporation	Iowa	Above Average / 3	3
	Illinois	Average / 2	5
	Missouri	Average / 3	6
American Electric Power Company Inc.	Arkansas	Average / 1	4
	Indiana	Average / 1	4
	Kentucky	Average / 2	5
	Louisiana (PSC)	Average / 2	5
	Michigan	Above Average / 3	3
	Ohio	Average / 3	6
	Oklahoma	Average / 2	5
	Texas (PUC)	Average / 3	6
	Virginia	Average / 1	4
	West Virginia	Below Average / 2	8
Avista Corporation	Alaska	Below Average / 1	7
CMS Energy Corporation	Michigan	Above Average / 3	3
Duke Energy Corporation	Florida	Above Average / 2	2
	Indiana	Average / 1	4
	Kentucky	Average / 2	5
	North Carolina	Above Average / 3	3
	Ohio	Average / 3	6
	South Carolina	Average / 3	6
Entergy Corporation	Arkansas	Average / 1	4
	Louisiana (PSC)	Average / 2	5
	Louisiana (NOCC)	Average / 3	6
	Mississippi	Above Average / 3	3
	Texas (PUC)	Average / 3	6
IDACORP Inc.	Idaho	Average / 2	5
	Nevada	Average / 2	5
	Oregon	Average / 2	5
	Wyoming	Average / 2	5
NextEra Energy Inc.	Florida	Above Average / 2	2
	Georgia	Above Average / 2	2
NorthWestern Corporation	Iowa	Above Average / 3	3
	Montana	Below Average / 1	7
	North Dakota	Average / 1	4
	South Dakota	Average / 2	5
	Wyoming	Average / 2	5
OGE Energy Corp.	Oklahoma	Average / 2	5
Otter Tail Corporation	Minnesota	Average / 2	5
	North Dakota	Average / 1	4
	South Dakota	Average / 2	5
Portland General Electric Company	Montana	Below Average / 1	7
	Oregon	Average / 2	5
	Washington	Average / 3	6
The Southern Company	Alabama	Above Average / 1	1
	Georgia	Above Average / 2	2
	Mississippi	Above Average / 3	3
Xcel Energy Inc.	Colorado	Average / 1	4
	Michigan	Above Average / 3	3
	Minnesota	Average / 2	5
	North Dakota	Average / 1	4
	New Mexico	Below Average / 2	8
	South Dakota	Average / 2	5
	Texas (PUC)	Average / 3	6
	Wisconsin	Above Average / 3	3
Proxy Group Average		Average / 1 to Average / 2	4.55
Evergy Metro / Evergy Kansas City	Kansas	Below Average / 1	7

Ranking Legend

Description	Value
Below Average / 3	9
Below Average / 2	8
Below Average / 1	7
Average / 3	6
Average / 2	5
Average / 1	4
Above Average / 3	3
Above Average / 2	2
Above Average / 1	1

Notes
[1] Source: State Regulatory Evaluations Regulatory Research Associates as of September 8 2021.
[2] AA/1= 1 AA/2= 2 AA/3= 3 A/1= 4 A/2= 5 A/3=6 BA/1= 7 BA/2= 8 BA/3= 9

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Exhibit AEB-11
Page 1 of 1

COMPARISON OF EVERGY METRO / EVERGY KANSAS CITY AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
ALLETE Inc.	Minnesota	Highly Credit Supportive	2
	North Dakota	Highly Credit Supportive	2
Alliant Energy Corporation	Iowa	Most Credit Supportive	1
	Minnesota	Highly Credit Supportive	2
	Wisconsin	Most Credit Supportive	1
Ameren Corporation	Iowa	Most Credit Supportive	1
	Illinois	Very Credit Supportive	3
	Missouri	Very Credit Supportive	3
American Electric Power Company Inc.	Arkansas	Highly Credit Supportive	2
	Indiana	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	Louisiana (PSC)	Highly Credit Supportive	2
	Michigan	Most Credit Supportive	1
	Ohio	Very Credit Supportive	3
	Oklahoma	Very Credit Supportive	3
	Texas (PUC)	Very Credit Supportive	3
	Virginia	Highly Credit Supportive	2
	West Virginia	Very Credit Supportive	3
Avista Corporation	Alaska	More Credit Supportive	4
CMS Energy Corporation	Michigan	Most Credit Supportive	1
Duke Energy Corporation	Florida	Most Credit Supportive	1
	Indiana	Highly Credit Supportive	2
	Kentucky	Most Credit Supportive	1
	North Carolina	Highly Credit Supportive	2
	Ohio	Very Credit Supportive	3
	South Carolina	More Credit Supportive	4
Entergy Corporation	Arkansas	Highly Credit Supportive	2
	Louisiana (PSC)	Highly Credit Supportive	2
	Louisiana (NOCC)	More Credit Supportive	4
	Mississippi	More Credit Supportive	4
	Texas (PUC)	Very Credit Supportive	3
IDACORP Inc.	Idaho	Very Credit Supportive	3
	Nevada	Very Credit Supportive	3
	Oregon	Highly Credit Supportive	2
	Wyoming	Very Credit Supportive	3
NextEra Energy Inc.	Florida	Most Credit Supportive	1
	Georgia	Highly Credit Supportive	2
NorthWestern Corporation	Iowa	Most Credit Supportive	1
	Montana	More Credit Supportive	4
	North Dakota	Highly Credit Supportive	2
	South Dakota	Very Credit Supportive	3
	Wyoming	Very Credit Supportive	3
OGE Energy Corp.	Oklahoma	Very Credit Supportive	3
Otter Tail Corporation	Minnesota	Highly Credit Supportive	2
	North Dakota	Highly Credit Supportive	2
	South Dakota	Very Credit Supportive	3
Portland General Electric Company	Montana	More Credit Supportive	4
	Oregon	Highly Credit Supportive	2
	Washington	Very Credit Supportive	3
The Southern Company	Alabama	Most Credit Supportive	1
	Georgia	Highly Credit Supportive	2
	Mississippi	More Credit Supportive	4
Xcel Energy Inc.	Colorado	Very Credit Supportive	3
	Michigan	Most Credit Supportive	1
	Minnesota	Highly Credit Supportive	2
	North Dakota	Highly Credit Supportive	2
	New Mexico	Credit Supportive	5
	South Dakota	Very Credit Supportive	3
	Texas (PUC)	Very Credit Supportive	3
	Wisconsin	Most Credit Supportive	1
Proxy Group Average		Very Credit Supportive to Highly Credit Supportive	2.41
Evergy Metro / Evergy Kansas City	Kansas	Highly Credit Supportive	2

Ranking Legend

Description	Value
Most credit supportive	1
Highly credit supportive	2
Very credit supportive	3
More credit supportive	4
Credit supportive	5

Notes
[1] S&P Global Ratings, "North American Util ty Regulatory Jurisdictions Updates Oklahoma Has Been Revised to Very Credit Supportive, Developments Continue Elsewhere," July 20, 2022.
[2] Most Credit Supp. 1, Highly Credit Supp. 2, Very Credit Supp. 3, More Credit Supp. 4, Credit Supp. 5

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CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2020Q4 - 2022Q3)				
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Short-term Debt Ratio	Total Capitalization
ALLETE, Inc.	ALE	57.22%	42.69%	0.00%	0.10%	100.00%
Alliant Energy Corporation	LNT	51.34%	46.60%	0.79%	1.26%	100.00%
Ameren Corporation	AEE	52.39%	45.62%	0.62%	1.37%	100.00%
American Electric Power Company, Inc.	AEP	46.98%	51.43%	0.00%	1.59%	100.00%
Avista Corporation	AVA	60.92%	39.02%	0.00%	0.07%	100.00%
CMS Energy Corporation	CMS	51.87%	47.18%	0.21%	0.74%	100.00%
Duke Energy Corporation	DUK	52.33%	46.07%	0.00%	1.59%	100.00%
Entergy Corporation	ETR	46.19%	53.71%	0.10%	0.00%	100.00%
IDACORP, Inc.	IDA	54.07%	45.65%	0.28%	0.00%	100.00%
NextEra Energy, Inc.	NEE	60.17%	38.36%	0.00%	1.48%	100.00%
NorthWestern Corporation	NWE	47.68%	52.04%	0.00%	0.28%	100.00%
OGE Energy Corp.	OGE	53.03%	45.19%	0.00%	1.78%	100.00%
Otter Tail Corporation	OTTR	52.85%	44.56%	0.00%	2.59%	100.00%
Portland General Electric Company	POR	45.35%	53.38%	0.00%	1.27%	100.00%
The Southern Company	SO	54.16%	44.72%	0.52%	0.60%	100.00%
Xcel Energy Inc.	XEL	54.65%	44.33%	0.00%	1.02%	100.00%
Average		52.58%	46.28%	0.16%	0.98%	
Median		52.62%	45.64%	0.00%	1.14%	
Maximum		60.92%	53.71%	0.79%	2.59%	
Minimum		45.35%	38.36%	0.00%	0.00%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, long-term debt and short-term debt of the operating subsidiaries.
[2] Electric and Natural Gas operating subsidiaries with data listed as N/A from S&P Capital IQ have been excluded from the analysis.

EVERGY KANSAS CENTRAL ELECTRIC UTILITY LONG-TERM DEBT SCHEDULE
PROJECTED JUNE 30, 2023

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Description	Date of Settlement	Date of Maturity	Interest Rate	Principal Amount of Issue	Net Proceeds	Yield to Maturity	Moody's A Utility Bond Index on Settlement date	Moody's Baa Utility Bond index on Settlement date	Weighted Cost of Debt	Weighted Cost at Moody's A Utility Bond Index	Weighted Cost at Moody's Baa Utility Bond Index
WR 2015 FMB 3.25% Due 2025	11/13/15	12/01/25	3.2500%	250,000,000	247,949,597	3.3466%	4.4300%	5.5900%	0.19%	0.26%	0.32%
WR 2016 FMB 2.55% Due 2026	06/20/16	07/01/26	2.5500%	350,000,000	345,238,685	2.7057%	3.7900%	4.4700%	0.21%	0.31%	0.36%
KGE 1994 La Cygne PCB Variable Due 2027	04/28/94	04/15/27	3.5400%	21,940,000	20,763,492	3.8276%	8.2200%	8.4800%	0.02%	0.04%	0.04%
WR 2017 FMB 3.10% Due 2027	03/06/17	04/01/27	3.1000%	300,000,000	296,205,083	3.2481%	4.2300%	4.6100%	0.21%	0.29%	0.32%
KGE 2016 PCB 2.50% Due 2031	06/01/16	06/01/31	2.5000%	50,000,000	48,015,631	2.8265%	3.9100%	4.6100%	0.03%	0.05%	0.05%
WR 1994 St. Marys PCB Variable Due 2032	04/28/94	04/15/32	3.5400%	45,000,000	43,694,021	3.6825%	8.2200%	8.4800%	0.04%	0.09%	0.09%
WR 1994 Wamego PCB Variable Due 2032	04/28/94	04/15/32	3.5400%	30,500,000	29,576,046	3.6889%	8.2200%	8.4800%	0.02%	0.06%	0.06%
KGE 1994 St. Marys PCB Variable Due 2032	04/28/94	04/15/32	3.6600%	14,500,000	14,015,257	3.8277%	8.2200%	8.4800%	0.01%	0.03%	0.03%
KGE 1994 Wamego PCB Variable Due 2032	04/28/94	04/15/32	3.6600%	10,000,000	9,647,351	3.8371%	8.2200%	8.4800%	0.01%	0.02%	0.02%
KGE 2007 FMB 6.53% Due 2037	10/15/07	12/15/37	6.5300%	175,000,000	173,937,727	6.5756%	6.2300%	6.4600%	0.26%	0.25%	0.26%
KGE 2008 FMB 6.64% Due 2038	05/15/08	05/15/38	6.6400%	100,000,000	100,175,656	6.6264%	6.2600%	6.7700%	0.15%	0.14%	0.16%
WR 2012 FMB 4.125% Due 2042	03/01/12	03/01/42	4.1250%	550,000,000	511,982,336	4.5496%	4.3600%	5.0500%	0.52%	0.55%	0.64%
WR 2013 FMB 4.10% Due 2043	03/28/13	04/01/43	4.1000%	430,000,000	417,173,662	4.2774%	4.1700%	4.6800%	0.41%	0.41%	0.47%
WR 2013 FMB 4.625% Due 2043	08/19/13	09/01/43	4.6250%	250,000,000	246,658,133	4.7085%	4.8700%	5.4300%	0.27%	0.28%	0.31%
KGE 2014 FMB 4.30% Due 2044	07/02/14	07/15/44	4.3000%	250,000,000	246,453,918	4.3853%	4.3500%	4.7600%	0.25%	0.25%	0.28%
WR 2015 FMB 4.25% Due 2045	11/13/15	12/01/45	4.2500%	300,000,000	233,257,431	5.8269%	4.4300%	5.5900%	0.29%	0.31%	0.39%
WR 2019 FMB 3.25% Due 2049	08/19/19	09/01/49	3.2500%	300,000,000	294,168,487	3.3531%	3.3100%	3.6500%	0.23%	0.23%	0.25%
WR 2020 FMB 3.45% Due 2050	04/09/20	04/15/50	3.4500%	500,000,000	477,284,920	3.7019%	3.4700%	4.0800%	0.40%	0.40%	0.47%
WR 2022 FMB 5.50% Due 2053	03/15/23	03/15/53	5.5000%	400,000,000	395,680,000	5.5745%	5.3800%	5.6700%	0.51%	0.50%	0.52%
Total				**4,326,940,000**	**4,151,877,433**				**4.03%**	**4.47%**	**5.05%**

Notes:
[1] - [6]: Provided by the company.
[7], [8]: Bloomberg, CapitalIQ.

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EVERGY KANSAS CENTRAL ELECTRIC UTILITY LONG-TERM DEBT SCHEDULE
PROJECTED JUNE 30, 2023

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
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Total				**4,326,940,000**	**4,151,877,433**				**4.03%**	**4.47%**	**5.05%**

Notes:
[1] - [6]: Provided by the company.
[7], [8]: Bloomberg, CapitalIQ.

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EVERGY KANSAS CAPITAL STRUCTURE
PROJECTED JUNE 30, 2023

	[1]	[2]	[3]	[4]
	Balance	Weight	Rate	Rate of Return
EVERGY KANSAS METRO				
Long-term Debt*	2,926,400,750	48.00%	4.372%	2.099%
Common Equity	3,169,665,643	52.00%	10.250%	5.330%
Total Capitalization	**6,096,066,393**	**100.00%**		**7.428%**
EVERGY KANSAS CENTRAL				
Long-term Debt*	4,285,963,478	47.96%	4.347%	2.085%
Common Equity	4,650,135,150	52.04%	10.250%	5.334%
Total Capitalization	**8,936,098,628**	**100.00%**		**7.419%**

Notes:

[1]: Provided by the companies.

[2] = [1] / Total Capitalization.

[3]: Weighted Average Cost of Capital for specific financing type.

[4] = [2] * [3].

*Includes unamortized debt expenses and discounts. There are no current maturities of long-term debt.

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COMMONWEALTH OF MASSACHUSETTS)
) ss:
COUNTY OF SUFFOLK)

VERIFICATION

Ann Bulkley, being duly sworn upon his oath deposes and states that she is a Principal with The Brattle Group, that she has read and is familiar with the foregoing Direct Testimony, and attests that the statements contained therein are true and correct to the best of her knowledge, information and belief.

Ann Bulkley

Subscribed and sworn to before me this 13 day of April, 2023.

Notary Public

My Appointment Expires: 6/30/2028

Gerard M. Rooney
NOTARY PUBLIC
Commonwealth of
Massachusetts
My Commission Expires
6/30/2028

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES	))))	FINAL DECISION AND ORDER; NOTICE OF ENTRY EL14-026

PROCEDURAL HISTORY

On March 31, 2014, Black Hills Power, Inc. (BHP) filed with the South Dakota Public Utilities Commission (Commission) an Application for Authority to Increase Electric Rates (Application) and supporting exhibits requesting approval to increase rates for electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27% based on BHP's test year ending September 30, 2013.[1] The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. The Application stated that a typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in BHP's South Dakota service territory. The Application requested an effective date of October 1, 2014, for the proposed rate increase which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station, then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14.

On April 11, 2014, BHP filed revised Exhibits A, B, C, and D. On April 16, 2014, the Commission issued an Order Assessing Filing Fee assessing a filing fee of up to the $250,000 maximum allowed by SDCL 49-1-8 to reimburse the actual expenses incurred by the Commission in processing this docket. On June 6, 2014, GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively Black Hills Industrial Intervenors or BHII) filed a Petition to Intervene, and Dakota Rural Action, Inc. (DRA) filed a Petition to Intervene. On June 18, 2014, BHP filed Black Hills Power, Inc.'s, Objection to the Intervention Petition of Dakota Rural Action and Black Hills Power, Inc.'s Response to Intervention Petition of Black Hills Industrial Intervenors.

On June 20, 2014, DRA filed Dakota Rural Action's Response to Black Hills Power, Inc.'s Objection to Dakota Rural Action's Petition to Intervene and Dakota Rural Action, Inc.'s Attachment to Paragraph 4 of Response to Black Hills Power, Inc.'s Objection to Dakota Rural Action's Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention, granting intervention to BHII and DRA, subject to the condition that DRA file an affidavit attesting to the members of DRA who were then current customers of BHP. On June 27, 2014, DRA filed a Supplemental Affidavit to Intervenor Dakota Rural Action, Inc.'s Petition to Intervene and Response to Black Hill Power, Inc.'s Objection.

[1] The Application, Commission Orders in the case, and all other filings and documents in the record are available on the Commission's web page for Docket EL14-026 at: http://www.puc.sd.gov/Dockets/Electric/2014/EL14-026.aspx

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On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates advising the Commission and the public of BHP's intent to implement its requested rate increase as of October 1, 2014. On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement and Settlement Agreement to settle outstanding issues between BHP and the South Dakota Science and Technology Authority (SDSTA Settlement Agreement). The SDSTA Settlement Agreement includes a Third Amendment to Electric Power Service Agreement Between Black Hills Power, Inc. and South Dakota Science and Technology Authority (Third Amendment). On September 10, 2014, the Commission's staff (Staff) filed a Staff Memorandum regarding the Third Amendment. On September 12, 2014, BHP filed its responses to Staff's ninth set of data requests. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis, authorizing BHP to implement the rates set forth in the SDSTA Settlement Agreement subject to the conditions set forth in the Staff Memorandum. On September 24, 2014, BHP filed a revised tariff page Section No. 3A, Sheet No. 1.

On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits (Settlement Stipulation). On December 12, 2014, the Commission issued a Scheduling Order. On December 30, 2014, the Commission issued an Order for and Notice of Hearing setting this matter for hearing on January 27-29, 2015, at the Matthew Training Center in Pierre. On December 30, 2014, BHII filed the pre-filed testimony of its witnesses Lane Kollen and Stephan J. Baron and associated exhibits. On January 15, 2015, Staff filed the pre-filed testimony of its witness David E. Peterson and a Staff Memorandum Supporting Settlement Stipulation and associated exhibits. On January 15, 2015, BHP filed the pre-filed rebuttal testimony of Kyle D. White, John J. Spanos, Jon Thurber, Christopher Kilpatrick, and Robert J. Hollibaugh. On January 20, 2015, BHP, BHII, and Staff filed exhibit and witness lists.

On January 23, 2015, BHII filed a Motion for Briefing of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, and Wharf Resources (U.S.A.), Inc. (Motion) requesting that the Commission issue an order establishing a post-hearing briefing schedule and recommending a schedule to be established by such order. The hearing was held as scheduled on January 27 and 28, 2015. Following the evidentiary hearing, the Commission considered the Motion and after discussion decided upon a schedule that would permit a decision to be rendered prior to the expiration of the one-year period commencing with the date the Application was filed. On January 29, 2015, the Commission issued a Post-Hearing Scheduling Order requiring all parties' post-hearing briefs to be filed and served on or before February 17, 2015, and setting the matter for Commission action on March 2, 2015.

On February 10, 2015, BHP and Staff filed an Amended Settlement Stipulation between BHP and Staff (Amended Stipulation) reflecting two changes to the factual bases supporting the agreed revenue requirement due to new information contained in pre-filed testimony filed after the Settlement Stipulation was entered into and filed and evidence introduced at the hearing. The first change corrects an error in the South Dakota jurisdictional allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Utility Holdings (BHUH) intercompany charges adjustment, reducing the revenue requirement by $286,041. The second change reflected in the Amended Stipulation accepts the $412,988 Wyodak operations and maintenance (O&M) adjustment as provided by BHP in Exhibit BHP 71. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. This represents a

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known and measurable increase to test year expense. On February 10, 2014, Staff filed a Staff Memorandum Supporting Amended Settlement Stipulation.

On February 17, 2015, BHP, BHII, and DRA filed Post-Hearing Briefs, and Staff filed a letter concurring with BHP's Post-Hearing Brief. On February 23, 2015, BHP and Staff filed a Joint Motion for Approval of Amended Settlement Stipulation. At its regular meeting on March 2, 2015, after questions by Commissioners of the parties, the Commission voted unanimously to Grant the Joint Motion for approval of Amended Settlement Stipulation between BHP and Staff and approve the terms and conditions stipulated therein as the decision of the Commission on the rate increase requested by BHP with an effective date of April 1, 2015, to approve the Settlement Agreement and contract with deviations between BHP and SDSTA, to approve the interim rate refund plan set forth as Exhibit 3 to the original Settlement Stipulation between BHP and Staff but a with refund period beginning in May 2015, and with carrying charges on refunds of 7% as stipulated between BHP and Staff in the original Settlement Stipulation. On March 5, 2015, BHP filed a Customer Notice, revised tariff sheets, and an Interim Refund Plan conforming to the Commission's action at the March 2, 2015, meeting.

FINDINGS OF FACT

Procedural Findings

1. The Procedural History set forth above is hereby incorporated by reference in its entirety in these Procedural Findings. The procedural findings set forth in the Procedural History are a substantially complete and accurate description of the material documents filed in this docket and the proceedings conducted and decisions rendered by the Commission in this matter.

Parties

2. The Applicant is Black Hills Power, Inc., a corporation organized under the laws of South Dakota. Ex BHP 1, p. 4.[2] BHP is a wholly-owned subsidiary of Black Hills Corporation. Ex BHP 9, pp. 2-3. BHP is an investor owned "public utility" as defined in SDCL 49-34A-1(12) that provides retail electric service in South Dakota. Ex BHP 1, pp. 1 and 5; Ex BHP 9, pp. 2-3.

3. On June 26, 2014, the Commission issued an Order Granting Intervention to GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) and Dakota Rural Action (DRA).

4. The BHII companies are a group of General Service, Large and Industrial Contract customers of BHP. Ex BHII 3, p. 4.

5. DRA is a member-based organization with an office located in Rapid City. Dakota Rural Action's Petition to Intervene. A number of DRA's members are customers of BHP.

[2] References to the January 27-28, 2015, Hearing Transcript are in the format "TR" followed by the Hearing Transcript page number(s) referenced, and references to Hearing Exhibits are in the format Ex followed by "BHP" for BHP exhibits, "BHII" for BHII exhibits, "Staff" for Staff exhibits, and "JT" for BHP/Staff joint exhibits followed by the exhibit number and, where applicable, the page number(s) referenced or other identifying reference and, where applicable, the attachment or sub-exhibit identifier and page number(s) referenced.

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Supplemental Affidavit to Intervenor Dakota Rural Action, Inc.'s Petition to Intervene and Response to Black Hill Power, Inc.'s Objection.

6. Staff also participated in the docket as a full party.

Amended Settlement Stipulation

7. BHP's Application as filed requested approval from the Commission to increase its rates for retail electric service to customers in its South Dakota service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month. The proposed changes would affect approximately 65,500 customers in South Dakota. The Application requested an effective date of October 1, 2014, for the proposed rate increase, which was the anticipated start-up date for BHP's Cheyenne Prairie Generating Station (CPGS), then under construction, and coincides with the 180 day limitation on suspension of a requested rate increase pursuant to SDCL 49-34A-14. Ex BHP 1, p. 3; Ex Staff 1, p. 4. The Application included an extensive, detailed set of schedules and pre-filed testimony in support of the proposed rates. Ex BHP 1, pp. 1-2; Exs BHP 4 through 58.

8. BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and an 8.48% overall rate of return on rate base. Ex BHP 5, Exhibit G, Statement G, p. 1; Ex BHP 23, p. 3; Ex BHP 46, pp. 7-8, 11-12; Ex BHP 48; TR 269.

9. The Application also requested approval of: an accounting order allowing BHP to use deferred accounting for the costs associated with the FutureTrack Workforce Development Program that deviate from the costs included in base rates; an accounting order for the Company's Winter Storm Atlas regulatory asset if the decision in the docket was not issued by December 31, 2014; revisions to the Energy Cost Adjustment tariff; and a modification to the major maintenance account to expense a portion of the plant overhaul cost each year based on a plant's planned maintenance cycle. Ex BHP 1, p. 3; Ex BHP 8, pp. 6-7; Ex BHP 15, pp. 14-15; Ex BHP 24, pp. 5-11, 14-17; Exs BHP 25-28.

10. Beginning immediately following BHP's filing of the Application on March 31, 2014, Staff and its outside consultants conducted an extensive review of the Application and the statements, exhibits, testimony, and working papers filed with the Application. In addition, Staff served at least 330 discovery requests for additional data and information on BHP and conducted a thorough analysis of BHP's responses thereto and also its responses to approximately 60 additional discovery requests served on BHP by BHII. Exhibit Staff 1, p. 5; TR pp. 263, 267-268.

11. Staff based its determination of an appropriate revenue requirement on a comprehensive analysis of the as-filed September 30, 2013, total BHP test year costs, and the additional information obtained through discovery that supported further post-test year adjustments. In particular, Staff first allocated total company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for appropriate post-test year changes. The Amended Settlement Stipulation incorporates numerous income adjustments and rate base adjustments. Ex Staff 1; Staff Memorandum Supporting Settlement Stipulation (Staff Memorandum); Staff Memorandum Supporting Amended Settlement Stipulation (Amended Staff Memorandum).

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12. Settlement discussions between Staff, BHP, BHII, and DRA commenced in late October, 2014. Thereafter, Staff and BHP held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. According to Staff's expert witness Peterson, substantially all of the issues raised by BHII's witness, Lane Kollen, were identified and discussed in such settlement discussions and were considered by Staff in its analysis and its negotiation of the Settlement Stipulation. Ex Staff 1, p. 8. Ultimately, Staff and BHP reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA did not elect to become parties to the Settlement Stipulation reached between BHP and Staff. Ex Staff 1, pp. 5-6. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. Exs JT 1-6.

13. In the Settlement Stipulation, BHP and Staff agreed that BHP's total revenue deficiency is $6,890,746 and that BHP's tariffs will be designed to produce an increase in annual base revenue levels of $6,890,746 or approximately 4.35% over total retail revenues at existing rates based on a South Dakota jurisdictional retail revenue requirement of $165,122,614. In the Settlement Stipulation, BHP and Staff agreed to a 7.76% rate of return on rate base. Ex JT 2, p. 4. A detailed explanation of the adjustments, data, analyses, and computations underlying the Settlement Stipulation's provisions to resolve the numerous matters at issue in this case between BHP and Staff is set forth in Staff's Memorandum in Support of Settlement Stipulation filed on January 15, 2015, together with the pre-filed testimony of Staff's expert witness, David E. Peterson, set forth in Ex Staff 1.

14. On February 10, 2015, following the filing of BHII's pre-filed testimony, Staff's pre-filed testimony, and BHP's pre-filed rebuttal testimony and the evidentiary hearing held on January 27-28, 2015, BHP and Staff jointly filed an Amended Settlement Stipulation, and Staff filed a Staff Memorandum Supporting Amended Settlement Stipulation. On February 23, 2015, BHP and Staff jointly filed a Joint Motion for Approval of Amended Settlement Stipulation. The Amended Stipulation seeks to correct an error in the South Dakota allocation of transmission load dispatch expense, FERC Account 561, for the Black Hills Corporation/Black Hills Utility Holdings intercompany charges adjustment, reducing the revenue requirement by $286,041. This error was brought to light in the pre-filed and hearing testimony of BHII witness Kollen and was acknowledged to be correct by Staff witness Peterson in his pre-filed testimony and in his hearing testimony. TR 163-164, 184; Ex BHII 1, p. 39-40; Ex BHP 70, p. 16; Ex Staff 1, p. 19.

15. A second change reflected in the Amended Stipulation involves the acceptance and inclusion of an expense adjustment of $412,988 for the South Dakota jurisdictional share of Wyodak generating plant O&M expenses as provided by BHP in its pre-filed testimony after the Settlement Stipulation was executed and filed. This adjustment updates production O&M costs at the Wyodak power plant from $3,045,652 incurred during the test year to $3,458,640 incurred from October 2013 through September 2014. Ex BHP 70, pp. 17-19; Ex BHP 71. This represents an increase to test year expense that was not known and measurable at the time the Settlement Stipulation was executed and filed but had become known and measurable at the time BHP's pre-filed rebuttal testimony exhibits were filed and became known and measurable prior to twenty-four months after the Application filing date. Ex BHP 70, pp. 17-19.

16. The Amended Stipulation uses the same calculation for cash working capital, net operating loss, interest synchronization, and bad debt adjustments as the Settlement

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Stipulation. The revenue requirement value of each adjustment changes, however, based on the resolution of various issues in the case. These adjustments are dependent on the pro forma rate base, expenses, and revenues, and were recalculated as a result of the BHUH allocation correction and the Wyodak O&M expense adjustment. Staff Memorandum in Support of Amended Settlement Stipulation, p. 3.

17. Although the Staff Memorandum in Support of Amended Settlement Stipulation Exhibit___(BAM-4) Schedule 1 – Amended Settlement SD Electric Revenue Requirement cost of service calculations show a revenue deficiency of $7,010,894, the revenue deficiency in the Amended Stipulation, Section III, ¶1 retains the $6,890,746 level provided in the original Settlement Stipulation. With the inclusion of the Wyodak O&M costs, the amended cost of service in the Amended Stipulation supports a revenue requirement greater than that agreed upon in the Amended Stipulation, and ratepayers will not incur the added rate case expense required to prepare revised rates and tariff sheets. Staff Memorandum in Support of Amended Settlement Stipulation, p. 3.

18. In addition to the inclusion of only a portion of the Wyodak O&M expense adjustment in rates agreed to in the Amended Stipulation and the maintenance of the total rate increase at the same amount as in the Settlement Stipulation, Section III, ¶13 extends the rate case filing moratorium provision an additional three months from what was agreed to in the Settlement Stipulation. Under this provision, BHP will not be allowed to file any rate application for an increase in base rates which would go into effect prior to January 1, 2017.

19. The Commission finds that the agreements, adjustments, and rates proposed in the Amended Stipulation, considered together with the rate case moratorium, are just and reasonable, and the Amended Stipulation is approved by the Commission.

SDSTA Settlement Agreement

20. The Amended Stipulation in Section III, ¶12 accepts and recommends Commission approval of the SDSTA Settlement Agreement and the Third Amendment incorporated therein. The Amended Stipulation and Third Amendment are contracts with deviations, which are agreements between a public utility and one or more customers that provide for the provision of service under rates, terms, and/or conditions that deviate from the utility's rates, terms, and conditions specified in the utility's tariffs filed with, and approved by, the Commission. Contracts with deviations are generally approved for very large loads or other special business development circumstances under the authority of SDCL 49-34A-8.3. On September 18, 2014, the Commission issued an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis, authorizing BHP to implement the rates set forth in the SDSTA Settlement Agreement for SDSTA subject to the following conditions:

> 1. If the contract with deviations is not subsequently approved by the Commission, the rates to be paid by SDSTA for the period on and after October 1, 2014, shall be the rates ultimately approved in the rate case for the applicable class of service, with the difference between the interim rates paid by SDSTA and the rates ultimately approved in the rate case for the applicable class of service to be subject to true-up and refund or repayment, as the case may be, with interest at the rate approved in a refund order of the Commission after final decision in the general rate case; or

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2. If the contract with deviations is subsequently approved by the Commission with modification of the settlement rates to be paid by SDSTA, the rates to be paid by SDSTA for the period on and after October 1, 2014, shall be such contract with deviation rates as are ultimately approved by the Commission, with the difference between the conditionally approved interim rates and the contract with deviation rates ultimately approved by the Commission to be subject to true-up and refund or repayment, as the case may be, with interest at the rate approved in the refund provisions of the Commission's order approving the contract with deviations with modified rates or, if refund is not ordered in such order, in the refund order of the Commission at the time of the general rate decision.

3. This approval does not pre-determine a Commission decision in the current or future rate case proceedings regarding rate treatment of revenue requirement shortfalls resulting from rates approved as contracts with deviations.

21. The SDSTA Settlement Agreement and Third Amendment were filed as confidential documents, as is generally, if not always, the case with contracts with deviations. The Commission finds that the SDSTA Settlement is just and reasonable and is approved by the Commission.

Black Hills Industrial Intervenors' Contested Issues

22. The issues addressed in Findings of Fact 23 through 55 were contested by BHII in its pre-filed and hearing testimony and/or its legal arguments at hearing, in its post-hearing brief, and in argument before the Commission at the Commission's decision hearing on March 2, 2015. Each of these issues is addressed separately below in the above-referenced Findings of Fact.

Allowable Test Year Adjustments under ARSD 20:10:13:44 and Applicable Statutes

23. A number of BHII's contested issues with the Settlement Stipulation and Amended Settlement Stipulation are primarily based on statutory interpretation and to such extent are issues of law, and the details of the Commission's legal rulings on such issues are set forth below in this decision's Conclusions of Law. The primary issue raised by BHII concerns the scope of what may be presented by an applicant for a rate increase within the twenty-four month cost of service adjustment period set forth in ARSD 20:10:13:44 and what may be considered by the Commission in rendering its decision, including the extent to which the Commission may consider capital cost additions and/or reductions, expense increases and/or reductions, and other relevant cost of service facts which become known and measurable during the pendency and processing of the case prior to the expiration of the twenty-four month period after the application is filed and which will be incurred during the period of 24 months after the filing of the application. ARSD 20:10:13:44 is set forth in Conclusion of Law 8.

24. In this case, the date 24 months after the end of the test year is September 30, 2015. TR 269.

25. BHII argues that ARSD 20:10:13:44 only allows the consideration of post-test year adjustments which were known and measurable at the time the rate increase application was filed. This position is based upon BHII's interpretation of the phrase "which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing." Ex BHII 1, p. 8.

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26. Staff expert witness Peterson testified that during the four plus decades that he has worked with Staff on rate cases, the consistent interpretation of ARSD 20:10:13:44, read together with SDCL 49-34A-19, has been that because a historic test year is used to set rates for a future period, the analysis and substance of a proposed change in utility rates should include both known expenses during the test year and also adjustments to reflect any changes that occurred after the test year that become known and measurable within the 24-month period provided for in ARSD 20:10:13:44 and SDCL 49-34A-19. Staff has interpreted these provisions to mean that the adjustments have to be sufficiently known and measurable at the time of its review of the hundreds of responses to discovery requests and filings in the case. TR 279. This has been Staff's consistent policy and is therefore what is reflected in the Settlement Stipulation. It is also Staff's responsibility to closely examine the evidence that such changes are known and measurable expenses. This is the standard that Staff has relied on for years, and the Commission has approved numerous rate case settlements based on that standard. TR 275-276.

27. As is set forth in Conclusions of Law 8 through 10, the Commission concluded that adjustments in the Amended Settlement Stipulation are within the allowable adjustment periods set forth in SDCL 49-34A-19 and ARSD 20:10:13:44. The Commission accordingly finds that substantial and sufficient evidence was produced, introduced, and received in evidence in this proceeding to demonstrate that the rates agreed to in the Amended Settlement Agreement are just and reasonable and will adequately meet BHP's need for revenues sufficient to enable it to meet its current cost of furnishing adequate, efficient, economical, and reasonable service.

Inclusion of Revenue Changes for Period Covered by Post-Test Year Adjustments

28. BHII argues that all post-test year adjustments must be accompanied by changes in revenue during the same period. Ex BHII 1, p. 8.

29. Staff's witness Peterson testified that post-test year adjustments that are revenue producing or income producing must reflect either the additional revenue or the additional income that results from that change in operation before they may be recognized as a known and measurable adjustment. BHP points out that those types of changes are not included in the Settlement Stipulation and Amended Stipulation between BHP and Staff. TR 273; Ex BHP 70, p. 4.

30. Staff and the Commission have previously interpreted this rule to mean that for any post-test year change in expense or investment that has an incremental revenue component (i.e., expenses or investments made to increase sales and/or to serve new customers), a corresponding revenue adjustment must also be recognized. It is for this reason that the Amended Stipulation does not include any costs associated with post-test year plant additions that are designed to improve sales or to serve new customers. Similarly, there is no corresponding revenue offset for any of the post-test year expense adjustments that are reflected in the Amended Stipulation. Therefore, the Amended Stipulation is consistent with prior Commission policy in this regard and with the governing administrative rule. Ex Staff 1, p. 9.

31. Staff's analysis has been that if ARSD 20:10:13:44 intended that all revenues, not just those associated with plant additions, are intended or are supposed to be recognized within the 24-month post-test year period, the rule would require a forecast test year. The Commission has never recognized that to be the intent of the rule, nor has the Commission ever adopted or accepted a forecast test year in an electric utility rate increase filing. Therefore, the

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only logical conclusion is that the revenue effect of specific post-test year changes has to be acknowledged or recognized in an adjustment before the adjustment itself can be reflected in the revenue requirement. That is the standard that Staff has relied on since the inception of the rule. TR 275-276.

32. In his pre-hearing testimony, BHII's witness Kollen testified that the Commission should limit any post-test year adjustment to the twelve month period immediately following the historical test year ended September 30, 2013. Ex BHII 1, p. 7. This opinion was also asserted by BHII's witness Baron. TR 252. The Commission finds that this would contravene the express language of ARSD 20:10:13:44 and that the Commission's discretion under SDCL 49-34A-19 has historically employed the full two-year adjustment period set forth in the statute. The Commission concludes that the appropriate test year adjustment period is 24 months.

FutureTrack and Associated O&M Costs

33. In its Application, BHP proposed to increase its expenses for its FutureTrack Workforce Development program. The primary purpose of this program was to recruit talent within critical areas to complete the advanced training necessary to fill highly skilled positions upon the retirement of existing employees. Ex BHP 19, p. 6. The Settlement Stipulation and Amended Stipulation both limit the inclusion of such costs to positions actually hired at the time of settlement negotiations without deferral of subsequently hired employee expenses, and did not include recovery for FutureTrack program additional hirings in the future. Ex Staff 1, p. 10; Staff Memorandum, p. 9. BHII's expert witness Kollen expressed the opinion that no recovery should be allowed at all for FutureTrack hirings because they were not known and measurable at the time the Application was filed. Ex BHII 1, pp. 25-30. The Commission finds that BHII's objection is not warranted.

Employee Additions and Eliminations

34. BHII objected to BHP's request for an adjustment to fund employee additions to those employee positions included in the test year. TR 182-183; Ex BHII 1, pp. 30-33. The Amended Stipulation limits recovery for employee additions to those actually hired and in service as of the date of the Settlement Stipulation. Ex Staff 1, p. 10. As with the previous FutureTrack issue, BHII's primary issues were that such additional hirings were not known and measurable as of the date the Application was filed and were speculative on a forward looking basis. The Amended Stipulation's limitation of this adjustment to actual hirings renders the future hiring issue moot. As to the post-test year filing issue, for the reasons set forth in Findings of Fact 23 through 27 and Conclusions of Law 6 through 10, the Commission finds that BHII's objection is not warranted.

NOL ADIT

35. BHII argued and presented both pre-filed and evidentiary hearing expert witness testimony that the Amended Stipulation's proposed inclusion of a tax-related net operating loss (NOL) accumulated deferred income taxes (ADIT) adjustment to the revenue requirement was inappropriate. Ex BHII 1, pp. 10-15; TR 178 et seq. BHP's expert witness Hollibaugh presented both pre-filed and evidentiary hearing testimony regarding the history leading to, the current status of, and the justification for continued maintenance of BHP's NOL ADIT. TR 148 et seq.; Ex BHP 73. Staff's expert witness Peterson testified that "Failure to provide for the deferred tax asset in rate base, as Mr. Kollen recommends, however, risks a violation of the IRS's normalization requirements." Ex Staff 1, p. 11. Based on its consideration of the testimony and

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supporting documentary evidence presented by both BHP and BHII, the Commission finds that the issue of the NOL ADIT is very complex and that measures to address the underlying tax cost consequences for both BHP and ratepayers can be addressed in more than one justifiable manner.

36. The Commission finds that the NOL ADIT methodology utilized in the past few years and proposed by BHP for approval in this docket has resulted, and will result, in a just and reasonable method of accounting for and reporting BHP's taxable income/loss status and liability/credit, was developed and put into use as a consequence of the unique circumstances presented by the financial challenges and resulting Congressional tax law responses thereto arising from the severe negative economic consequences stemming from the early 2000s and 2008 and ensuing years' recessions, and will result in just and reasonable rate impacts to BHP customers.

Incentive Compensation

37. BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from BHP's affiliates BHUH and BHSC. Ex BHII 6. In the Amended Stipulation, $666,000 of the Company's test year incentive compensation expenses is excluded. This is the amount that BHP identified as being tied to the Company's financial results. Ex Staff 1, p. 17. The Amended Stipulation did not change and includes this provision.

38. BHP provided evidence that employee incentive compensation plans are widely employed by utilities throughout the country and that it is necessary for BHP to provide employee incentive opportunities that are competitive with other companies in the industry. Another goal of the program is to focus employees on important objectives to improve the performance of utility operations by focusing on improvements to operational excellence, safety, reliability, and customer satisfaction. TR , 300; Ex BHP 22, pp. 8, 10.

39. BHII's expert witness Kollen offered opinion evidence that in addition to the amount excluded in the Settlement Stipulation, $149,000 in performance plan expenses and $739,000 in incentive restricted stock expenses should be excluded because these additional amounts represent incentive awards that are similar in nature to those excluded in the Settlement Stipulation. BHII witness Kollen also offered the opinion that by embedding such incentives in rates, BHP itself is not incentivized to manage toward operational performance. TR 184; Ex BHII 1, pp. 35-37; Ex BHII 6, p. 2.

40. In settlement discussions, Staff raised issues with the incentive compensation plan and the payments made under the plan. Staff's expert witness Peterson testified he did not necessarily disagree with Mr. Kollen's characterization of the incentive awards and in fact, had initially pursued the same issues on behalf of the Commission Staff earlier in this proceeding. In the end, however, the Commission Staff conceded this issue and agreed to exclude the $666,000 related specifically to financial performance, recognizing that the incentive compensation exclusion embodied in the settlement is essentially the same type of exclusion the Commission has approved for BHP in prior base rate case settlements and for other South Dakota utilities. Therefore, Mr. Peterson supported the exclusion that is contained in the Settlement Stipulation and recommended that the Commission reject Mr. Kollen's recommendation to expand the exclusion at this time. TR 285-287; Ex Staff 1, pp. 17-18. The Commission finds that the incentive compensation plan included in the Amended Stipulation does not render the Amended Stipulation unjust and unreasonable.

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Pension Expense Normalization

41. As documented in the evidence presented in the case , BHP's pension expense varies significantly year-by-year. Ex Staff 1, p. 16. For example, the Company's test year pension expense was $2,844,759. For 2014, however, the expense dipped down to $976,122. To remedy the problem caused by the fluctuating expense for ratemaking purposes, BHP proposed, and the Staff accepted for settlement purposes, a normalization adjustment based on the average annual expense during the five-year period 2010-2014. These years included a year in which the pension expense was high at $3.25 million (2012) and a year in which the expense was low -- $976,122 (2014). The five-year average expense used for rate setting purposes was $2,336,305. As pointed out in Staff witness Peterson's testimony at hearing, the five-year average that was agreed upon by BHP and the Staff represented over a $500,000 reduction in the test year expense. TR 282.

42. BHII objected to the treatment of the pension expense in the Stipulation characterizing it as "opportunistic" in that it does not reduce the test year expense far enough and it prevents BHP ratepayers from receiving the benefit from the lower pension expense in 2014 that the Company enjoyed. Rather, BHII witness Mr. Kollen recommended that BHP's 2014 pension expense be recognized for ratemaking purposes. Ex BHII 1, pp. 33-34.

43. The Commission finds that it is BHII's position, not that of BHP and the Staff, which is opportunistic in this instance with respect to the pension expense. BHII's recommendation would set rates based on the lowest pension expense experienced in the last five years. BHII's recommendation is particularly egregious in this instance given that BHP's witness Thurber testified that the Company's most recent estimate of its 2015 pension expense is $2,056,581 – which is considerably higher than its 2014 expense that Mr. Kollen recommends and similar to the five-year average reflected in the Settlement Agreement. Ex BHP 70, pp. 22-23. The Commission also finds that the normalization treatment of a widely varying expense is consistent with sound regulatory principles and that the Commission has routinely relied on the normalization treatment in prior cases before the Commission, e.g. storm damage expense and uncollectible expenses. The facts and circumstances surrounding the pension expense make it appropriate to apply normalization treatment in this instance. Finally, the Commission further finds that Mr. Kollen's recommended adjustment is internally inconsistent with BHII's position regarding post-test year adjustments in that BHII's witness did not include a revenue adjustment to correspond to its proposed expense adjustment even though BHII incorrectly contends that a revenue adjustment is required for each post-test year adjustment.

Retired Steam Plants Decommissioning Expense

44. In 2014, BHP began to decommission its Neil Simpson 1, Ben French, and Osage coal-fired power plants. The Company expects the decommissioning to be completed by September 2015. BHP proposed to amortize the estimated costs associated with the retirement and decommissioning activities over five years and to include the unamortized balance in rate base. The Settlement Stipulation removes all of the contingency allowances that were included in BHP's original cost estimate. The Settlement Stipulation also revises the amount included for obsolete inventories and reflects a ten-year rather than a five-year amortization period for final retirement and decommissioning costs.

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45. BHII objects to the treatment of final retirement and decommission costs associated with these three steam generating stations because it contends "[t]he Company had not yet incurred most of the decommissioning costs that it seeks to include in rate base as of October 1, 2014, twelve months after the end of the historic test year." Ex BHII 1, p. 16.

46. As discussed elsewhere in this Order, the Commission finds no legitimate basis for Mr. Kollen's artificial twelve-month post-test year cut-off. ARSD 20:10:13:44 clearly allows that the Commission look up to 24-months post-test year when evaluating expense adjustments such as this. Therefore, the Commission rejects BHII's recommendation and adopts as just and reasonable the adjusted ten-year amortization expense reflected in the Settlement Stipulation.

Affiliate Allocations

47. The Amended Stipulation includes actual billings by BHP's affiliates – Black Hills Corp. and Black Hills Utility Holdings – to the Company for the twelve months ended August 31, 2014. Thus, the Settlement Stipulation reflects known costs experienced by BHP well within the twenty-four month post-test year period provided for in ARSD 20:10:13:44.

48. BHII objects to any increase in affiliate charges. BHII witness Mr. Kollen contends that there is no justification for the increases in affiliate charges and, further, that the magnitude of the increase is unreasonable on its face. Therefore, Mr. Kollen recommended that the post-test year expense be excluded from BHP's revenue requirement. Ex BHII 1, pp. 37-40.

49. The Commission finds that the affiliate expenses included in the Amended Stipulation are, in fact, the actual expenses that were billed to BHP by its affiliates – Black Hills Corp. and Black Hills Utilities Holdings. Therefore, the affiliate expense adjustments reflected in the Amended Stipulation are known and measurable and just and reasonable for inclusion in BHP's revenue requirement. BHII's contention of these costs being unreasonable on their face is without merit and is hereby rejected.

Steam and Other Production Plant Net Salvage

50. The proposed adjustment to net negative salvage reflects an estimated negative increase to the net of estimated salvage income and cost of removal, or an increase in the shortfall from projected salvage income less than the projected cost of removal. BHII Witness Kollen listed several reasons why he rejected BHP's proposed adjustment as well as the revised Settlement adjustment as set forth in Finding 51.

51. First, the basis for the calculation of the terminal net salvage is flawed and unreliable, resulting in an excessive net negative salvage cost and percentage. Second, this may represent an undisclosed proposal to change the Commission's policy for decommissioning cost recovery from recovery *after* the retirement of the plants (as is the case in this proceeding for the three retired coal-fired plants) to recovery *before* the future retirement of the plants. Third, the increase in net negative salvage is not necessary at this time. The Commission is not required to provide recovery of unknown future costs in present rates. The Commission's current policy appears to be to determine the appropriate manner of decommissioning (and associated costs) *after* plants are retired. This policy is prudent for ratepayers and still ensures that the Company recovers its costs. Ex BHII 1, pp. 47-48.

52. Staff Witness Peterson disagreed, stating that "however desirable it might be to have all elements of the revenue requirement based on absolutely known and measurable

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costs, depreciation allowances must reflect estimates because neither the service life of the asset nor the cost of the act of retirement are known until the asset has been retired. Depreciation allowances represent allocations of capital costs of an asset to the time periods as the asset provides service to customers over a long period of time. In the absence of making such estimates, ratepayers benefitting from the service provided by the asset will avoid these costs and cost recovery would be shifted to future ratepayers not benefitting from that service. I know of nothing that even suggests an existing Commission policy of refusing to recognize these retirement-related costs until after the plant is retired." Ex Staff 1, p. 20. The Commission finds that the Amended Stipulation reasonably addresses the net salvage cost issue.

LIDAR

53. As with BHP's decommissioning costs, BHP's LIDAR costs are governed and capped by a fixed rate contract. In the opinion of Staff witness Peterson, these costs are sufficiently known and measurable to be appropriately recognized in rates. The five-year amortization period reflected in the Amended Stipulation was determined to be appropriate because five years is the expected frequency for LIDAR surveying activities. It would be inappropriate to employ a ten-year amortization period as BHII witness Kollen recommends because to do so would unjustifiably burden BHP ratepayers, including BHII members, in years six through ten with costs for two different LIDAR surveys. A five-year amortization matches with the planned survey interval and is therefore more appropriate for these costs. Ex Staff 1, p. 15.

Class Cost of Service Study

54. Because BHII accepts the apportionment of the overall approved revenue increase reflected in the Settlement Stipulation, there are no remaining issues to be decided by the Commission regarding the spread of the rate change among the rate classes. Ex. Staff 1, p. 21.

55. Only the spread of the revenue change among the rate classes is being resolved by the Settlement Stipulation, and through Mr. Baron's testimony, BHII is accepting the settlement resolution concerning the spread of the revenue change. Under the Settlement Stipulation, BHP, the Commission Staff and the BHII are free to advocate whatever they choose concerning the CCOSS in BHP's next base rate proceeding. Therefore, it is not necessary for the Commission to rule on any CCOSS issue in this proceeding; nor is it necessary for the Commission to direct BHP to file a CCOSS in any particular manner in the next case. Ex Staff 1, pp. 21-22.

Refund of Overcharges

56. Interim rates were implemented on October 1, 2014. Approval of the Amended Settlement Stipulation will authorize a rate increase less than the interim rate level. BHP will refund to customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014, through the effective date of new rates, plus interest. Ex JT 2, p. 5.

57. Refunds with carrying charges of seven percent (7%) annual interest will occur in May 2015, in accordance with BHP's proposed Interim Refund Plan. March 2nd transcript, pp. 29-30.

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Tariff Sheets

58. The revised tariff sheets proposed by BHP are as follows:

South Dakota Electric Rate Book

Section No. 1	
Twenty-fifth Revised Sheet No. 3	Replaces Twenty-fourth Revised Sheet No. 3
Section No. 3	
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Thirteenth Revised Sheet No. 2	Replaces Twelfth Revised Sheet No. 2
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Fifteenth Revised Sheet No. 7	Replaces Fourteenth Revised Sheet No. 7
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Fifteenth Revised Sheet No. 9	Replaces Fourteenth Revised Sheet No. 9
Thirteenth Revised Sheet No. 10	Replaces Twelfth Revised Sheet No. 10
Fifteenth Revised Sheet No. 11	Replaces Fourteenth Revised Sheet No. 11
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Sixth Revised Sheet No. 33	Replaces Fifth Revised Sheet No. 33
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Sixth Revised Sheet No. 9	Replaces Fifth Revised Sheet No. 9
Sixth Revised Sheet No. 10	Replaces Fifth Revised Sheet No. 10
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Seventh Revised Sheet No. 12	Replaces Sixth Revised Sheet No. 12
Ninth Revised Sheet No. 13	Replaces Eighth Revised Sheet No. 13
Sixth Revised Sheet No. 14	Replaces Fifth Revised Sheet No. 14
Sixth Revised Sheet No. 15	Replaces Fifth Revised Sheet No. 15
Seventh Revised Sheet No. 16	Replaces Sixth Revised Sheet No. 16
Third Revised Sheet No. 17	Replaces Second Revised Sheet No. 17
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Section 3B	
Sixth Revised Sheet No. 1	Replaces Fifth Revised Sheet No. 1
Fifth Revised Sheet No. 2	Replaces Fourth Revised Sheet No. 2
Fifth Revised Sheet No. 3	Replaces Fourth Revised Sheet No. 3
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Sixth Revised Sheet No. 5	Replaces Fifth Revised Sheet No. 5
Sixth Revised Sheet No. 8	Replaces Fifth Revised Sheet No. 8
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Section 3C	
Twelfth Revised Sheet No. 5	Replaces Eleventh Revised Sheet No. 5
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Sixth Revised Sheet No. 12	Replaces Fifth Revised Sheet No. 12
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Fourth Revised Sheet No. 4	Replaces Third Revised Sheet No. 4
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General

59. As stated in the Staff Memorandum, with respect to a Settlement Stipulation, petty criticisms can be levied against individual elements of the Settlement Stipulation. Because it is an agreed resolution of the case, however, a settlement stipulation is more appropriately judged on the basis of its overall resolution of the case because it involves trade-offs between the parties to it. The Commission believes that this is the appropriate way of assessing the justness and reasonableness of this Amended Stipulation as well. BHII focuses on the minute details of the Settlement Stipulation in isolation.

60. Staff witness Peterson testified that Staff believes that the end result of the Settlement Stipulation results in just and reasonable rates, and it reasonably reflects the cost that BHP will incur going forward. There were a number of issues which the Staff and the company disagreed on. The Staff's resolution of those issues is stated in the Staff Memorandum, but BHP had its own basis for settling certain issues which were either advantageous or adverse to the company. Staff does not see the company's analysis of that. But the end result, Staff believes, was just and reasonable rates and reasonably reflects the cost that the company expects to incur going forward. TR 280.

61. The Commission finds that the rates, terms and conditions in the Amended Stipulation demonstrate a thorough, penetrating, and credible analysis by Staff and its expert witnesses of the data and assumptions underlying the Application and the Amended Settlement Stipulation; balance fairly the interests of BHP and its customers; recover no more than BHP's current revenue requirements, including a reasonable return to its stockholders commensurate with its cost of equity capital; are supported by substantial evidence; and meet the just and reasonable standard set forth in SDCL 49-34A-6, as more specifically delineated in SDCL 49-34A-8, the unreasonable preference or advantage and unreasonable prejudice or disadvantage prohibitory standards of SDCL 49-34A-3, the fair and reasonable return standard of SDCL 49-34A-8, and are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers as provided in SDCL 49-34A-8.4. These settlement rates allow BHP a reasonable opportunity to earn a return that is adequate to enable it to continue providing safe, adequate, and reliable service to its South Dakota retail customers.

62. The Commission finds that neither the SDSTA Settlement Agreement nor the Commission's approval of the SDSTA Settlement Agreement has affected the costs to be recovered from BHP's other customers under the Amended Settlement Stipulation.

63. To the extent that any Conclusion of Law set forth below is more appropriately a finding of fact, that Conclusion of Law is incorporated by reference as a Finding of Fact.

CONCLUSIONS OF LAW

1. The following statutes and rules are applicable to this proceeding and vest the Commission with jurisdiction over this matter: SDCL Chapters 1-26 and 49-34A, including 1-26-20, 49-34A-3, 49-34A-4, 49-34A-6, 49-34A-8, 49-34A-8.4, 49-34A-10, 49-34A-11, 49-34A-12, 49-34A-13, 49-34A-13.1, 49-34A-14, 49-34A-19, 49-34A-19.1, 49-34A-19.2, 49-34A-21, and 49-34A-22, and ARSD Chapters 20:10:01 and 20:10:13.

2. The primary issue raised by BHII concerns the scope of what adjustments may be presented by an applicant for a rate increase within the twenty-four month cost of service

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adjustment period set forth in ARSD 20:10:13:44 and what may be considered by the Commission in rendering its decision, including the extent to which the Commission may consider capital cost additions and/or reductions, expense increases and/or reductions, and other relevant cost of service facts which become known and measurable during the pendency and processing of the case prior to the expiration of the twenty-four month period after the application is filed and which will be incurred during the period of 24 months after the filing of the application.

3. SDCL 49-34A-6 provides:

Every rate made, demanded or received by any public utility shall be just and reasonable. Every unjust or unreasonable rate shall be prohibited. The Public Utilities Commission is hereby authorized, empowered and directed to regulate all rates, fees and charges for the public utility service of all public utilities, including penalty for late payments, to the end that the public shall pay only just and reasonable rates for service rendered.

4. SDCL 49-34A-8 provides:

The commission, in the exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, economical, and reasonable service and to the need of the public utility for revenues sufficient to enable it to meet its total current cost of furnishing such service, including taxes and interest, and including adequate provision for depreciation of its utility property used and necessary in rendering service to the public, and to earn a fair and reasonable return upon the value of its property.

5. SDCL 49-34A-8.4 provides:

The burden is on the public utility to establish that the underlying costs of any rates, charges, or automatic adjustment charges filed under this chapter are prudent, efficient, and economical and are reasonable and necessary to provide service to the public utility's customers in this state.

6. SDCL 49-34A-19 provides in relevant part:

In determining the revenue requirement the commission shall consider revenue, expenses, cost of capital and any other factors or evidence material and relevant thereto. The commission may take into consideration the reasonable income and expenses that will be forthcoming in a period of twenty-four months in advance of the test year.

7. ARSD 20:10:13:01(11) provides as follows:

"Test period," the test period outlined in § 20:10:13:44, except that if additional material is filed by the utility, a test period is any 12 consecutive months beginning no later than the proposed effective date of the rate application.

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8. ARSD 20:10:13:44 provides as follows:

> The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months of actual experience ending no earlier than 6 months before the date of filing of the data required by §§ 20:10:13:40 and 20:10:13:43 unless good cause for extension is shown. The analysis shall include the return, taxes, depreciation, and operating expenses and an allocation of such costs to the services rendered. The information submitted with the statement shall show the data itemized in this section for the test period, as reflected on the books of the filing public utility. Proposed adjustments to book costs shall be shown separately and shall be fully supported, including schedules showing their derivation, where appropriate. However, no adjustments shall be permitted unless they are based on changes in facilities, operations, or costs which are known with reasonable certainty and measurable with reasonable accuracy at the time of the filing and which will become effective within 24 months of the last month of the test period used for this section and unless expected changes in revenue are also shown for the same period.

9. As set forth in Findings of Fact 24, these provisions have for decades been interpreted together as providing for a historic test year as the cost of service basis period, but also, in part because such cost of service data are used to set rates for a future period, the analysis and substance of a proposed change in utility rates should include both known and measurable expenses during the test year and adjustments to reflect any changes that occurred after the test year that become known and measurable within the 24-month period for case processing provided for in ARSD 20:10:13:44 and SDCL 49-34A-19. Staff has interpreted these provisions to mean that the adjustments have to be sufficiently known and measurable at the time of their submission for Staff review of the responses to hundreds of discovery requests and filings in the case. Although the phrase "in advance of" is anomalous when read together with the word "forthcoming," the Commission concludes that the intent of SDCL 49-34A-19 is to permit the consideration of cost of service evidence that becomes known and measurable during the twenty-four month period following the end of the test year, that such interpretation is not inconsistent with the phrase "at the time of the filing" due to the voluminous "filings" in a rate case over a two year period in most rate cases, and that such interpretation results in the most accurate real-time basis for the utility's rates, thus minimizing the need for an immediate or near term filing by the utility of a follow-on rate case to recover such costs.

10. As to the issue of revenue during the twenty-four month rate case processing period, BHII argues that BHP and Staff neglected to provide and/or consider evidence of BHP's revenue during such period. BHII argues that this violates the matching principle and also runs contrary to SDCL 49-34A-19. BHP and Staff in contrast argue that the matching principle is not violated because the only adjustments accepted by Staff are adjustments that have no revenue generating component to them. The Commission concludes that none of the cost adjustments included in the Amended Settlement Stipulation result in additional revenue for BHP, and, in the context of a settlement stipulation that very significantly reduces the revenue requirement from what was requested by BHP in its Application and supported by its experts in its pre-filed and hearing testimony, such adjustments are just and reasonable.

11. With respect to BHII's argument at the March 2, 2015, decision hearing that BHII was not afforded due process to contest the Amended Settlement Stipulation's correction of the error in the BHUH allocation, the Commission concludes that this substantive amendment to the original Settlement Stipulation occurred precisely as a result of evidence introduced and

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considered at the evidentiary hearing and the pre-filed testimony filed prior to the hearing and received in evidence at the hearing. The error in the calculation of the BHUH allocation was pointed out in BHII's expert witness Kollen's pre-filed testimony and acknowledged by BHP witness Thurber and Staff witness Peterson to be accurate in their pre-filed testimony and at hearing. The Commission has already heard the evidence and arguments regarding this amendment to the Settlement Stipulation, and nothing would be gained by another hearing on a matter that has already been heard.

12. No statute or rule precludes the inclusion of employee incentive compensation in the utility's cost of service and revenue requirement. The Commission's decision whether to allow incentive compensation and, if so, subject to what limitations are judgment calls concerning what meets the just and reasonable standard.

It is therefore

ORDERED, that the Amended Settlement Stipulation between Black Hills Power, Inc. and Staff is approved as the substance of the decision of the Commission in this docket with an effective date of April 1, 2015, and with refunds of interim rate billings in excess of the approved rates plus carrying charges of seven percent (7%) annual interest to occur in May, 2015, in accordance with BHP's proposed Interim Refund Plan. It is further

ORDERED, that the Settlement Agreement between Black Hills Power, Inc. and the South Dakota Science and Technology Authority and the Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority are approved and refunds to SDSTA shall not therefore be necessary.

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NOTICE OF ENTRY AND OF RIGHT TO APPEAL

PLEASE TAKE NOTICE that this Final Decision and Order; Notice of Entry was duly issued and entered on the 17th day of April, 2015. Pursuant to SDCL 1-26-32, this Final Decision and Order will take effect 10 days after the date of receipt or failure to accept delivery of the decision by the parties. Pursuant to ARSD 20:10:01:30.01, an application for a rehearing or reconsideration may be made by filing a written petition with the Commission within 30 days after the date of issuance of this Final Decision and Order; Notice of Entry. Pursuant to SDCL 1-26-31, the parties have the right to appeal this Final Decision and Order to the appropriate Circuit Court by serving notice of appeal of this decision to the circuit court within thirty (30) days after the date of service of this Notice of Decision.

Dated at Pierre, South Dakota, this 17th day of April, 2015.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically or by mail.

By: _____

Date: 4/17/15

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

CHRIS NELSON, Chairman

KRISTIE FIEGEN, Commissioner

GARY HANSON, Commissioner

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR AUTHORITY TO INCREASE ITS ELECTRIC RATES

STAFF MEMORANDUM SUPPORTING
SETTLEMENT STIPULATION

DOCKET EL14-026

Commission Staff (Staff) submits this Memorandum in support of the Settlement Stipulation (Settlement) of December 8, 2014, between Staff and Black Hills Power Company (BHP or Company) in the above-captioned matter.

BACKGROUND

On March 31, 2014, the Company filed an application with the South Dakota Public Utilities Commission (Commission) requesting approval to increase rates for electric service to customers in its South Dakota retail service territory by approximately $14.6 million annually or approximately 9.27%. A typical residential electric customer using 650 kWh per month would see an increase of $10.91 per month.

BHP's proposed increase was based on a historical test year ended September 30, 2013, adjusted for what BHP believed to be known and measurable changes, a 10.25% return on common equity, and a 8.48% overall rate of return on rate base.

The Commission officially noticed BHP's filing on April 3, 2014, and set an intervention deadline of June 6, 2014. On April 11, 2014, BHP filed revisions to certain pages originally filed in the application. On April 16, 2014, the Commission issued an Order Assessing Filing Fee. On June 6, 2014, a Petition to Intervene of GCC Dacotah, Inc., Pete Lien & Sons, Inc., Rushmore Forest Products, Inc., Spearfish Forest Products, Inc., Rapid City Regional Hospital, Inc., and Wharf Resources (U.S.A.), Inc. (collectively, Black Hills Industrial Intervenors or BHII) was filed. On June 6, 2014, Dakota Rural Action (DRA) also filed a Petition to Intervene. On June 26, 2014, the Commission issued an Order Granting Intervention to Black Hills Industrial Intervenors. On June 26, 2014, the Commission granted intervention to Dakota Rural Action subject to its filing an affidavit, which was filed on June 27, 2014. On September 3, 2014, BHP filed a Notice of Intent to Implement Interim Rates effective on and after October 1, 2014.

On September 4, 2014, BHP filed a Motion for Approval of Settlement Agreement, Confidential Settlement Agreement between Black Hills Power, Inc. and South Dakota Science and Technology Authority (SDSTA), including the associated Third Amendment to Electric Power Service Agreement between Black Hills Power, Inc. and SDSTA, and relevant exhibits. On September 10, 2014, Staff filed its memorandum regarding the Contracts with Deviations. On September 18, 2014, the Commission issued

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an Order Conditionally Authorizing and Approving Implementation of Contract with Deviations Rates on an Interim Basis.

Settlement discussions between Staff, BHP, BHII, and DRA commenced on October 28, 2014. Thereafter, Staff and BHP (jointly, the Parties) held several settlement discussions in an effort to arrive at a mutually acceptable resolution of the issues presented in BHP's filing. Ultimately, the Parties reached a comprehensive agreement on BHP's overall revenue deficiency and other issues presented in this case including, but not limited to, class revenue responsibilities, rate design, and tariff concerns. BHII and DRA are not parties to the settlement. On December 9, 2014, BHP and Staff jointly filed a Joint Motion for Approval of Settlement Stipulation, Settlement Stipulation, and Exhibits. On December 12, 2014, the Commission issued a Scheduling Order setting this matter for hearing on January 27-29, 2015. On December 30, 2014, the Commission issued an Order for and Notice of Hearing.

BHII filed Direct Testimony and Exhibits of Lane Kollen and Direct Testimony and Exhibits of Stephen J. Baron on December 30, 2014. No testimony was filed by DRA. This Memorandum supports Staff's view of the settlement. Staff Witness Dave Peterson's direct testimony addresses specific items discussed in Mr. Kollen's testimony and Mr. Baron's testimony.

OVERVIEW OF SETTLEMENT

Staff based its revenue requirement determination on its comprehensive analysis of BHP's filing and information obtained during discovery. Staff accepted some Company adjustments, made corrections where necessary, modified other adjustments, and rejected those that do not qualify as known and reasonably measurable. Lastly, Staff introduced new adjustments not reflected in BHP's filed case.

Company and Staff positions were discussed thoroughly at the settlement conferences. As a result, some positions were modified and others were accepted where consensus was found. Ultimately, the Parties agreed on a comprehensive resolution of all issues. Staff believes the settlement is based on sound regulatory principles and avoids additional costly and unnecessary litigation.

The Parties agree BHP's revenue deficiency is approximately $6,890,746, which results in an approximate 4.35% increase in retail revenue. This revenue requirement and supporting calculations described in this Memorandum and attachments depict Staff's positions regarding all components of BHP's South Dakota jurisdictional revenue requirement.

STAFF OVERVIEW OF SETTLEMENT

Staff's determination of the settlement revenue requirement begins with total Company test year costs for the twelve months ended September 30, 2013, and allocates those total Company amounts to the South Dakota retail jurisdiction. Staff then adjusted the September 30, 2013, test year results for known and measurable post-test year changes. Staff Exhibit___(BAM-1), Schedule 3 illustrates Staff's determination of BHP's *pro forma* operating income under present rates. Staff Exhibit___(BAM-2), Schedule 2 illustrates Staff's calculation of BHP's South Dakota retail rate base, and Staff Exhibit___(BAM-1), Schedule 2 and Staff Exhibit___(BAM-2), Schedule 1 summarize the positions. Staff Exhibit___(BAM-1), Schedule 1 summarizes Staff's determination of BHP's revenue deficiency and total revenue requirement collected through base rates.

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The base revenue increase by rate schedule is shown on Staff Exhibit___(PJS-2), Schedule 1. Staff Exhibit___(PJS-2), Schedules 2-1 through 2-5 reflect the settlement base rates for each rate schedule. The comparison between present and settlement rates and resulting bill impacts for the Residential Service rate schedules is shown on Exhibit___(PJS-2), Schedule 3.

Unless otherwise noted, all of the changes discussed below are changes from the Company's filed position.

RATE BASE

Average Rate Base – Both the Company and Staff arrived at a test year average rate base based on an average of the 13 month-end account balances, September 30, 2012, through September 30, 2013.

CPGS Plant Addition – BHP proposed an adjustment to increase plant in service for projected capital costs associated with the Cheyenne Prairie Generating Station (CPGS). The Company included in rate base the actual costs incurred as of December 31, 2013, and estimates of the remaining completion costs. The settlement determination revises the Company's adjustment to reflect actual costs as of October 31, 2014, and reasonably known and measurable changes after October 31, 2014. The settlement also reflects the associated accumulated deferred income taxes. The net effect of these changes is to reduce rate base by approximately $2,156,000.

Test Year Plant In Service Annualization – The Company proposed an adjustment to annualize test year non-revenue producing plant additions that were completed during the test year. The settlement determination revises the Company's adjustment to: 1) Remove the amounts related to eight projects that appear to be revenue producing; and 2) Reduce the amounts related to two projects for contributions made by CenturyLink. The settlement also includes accumulated deferred income taxes arising from these projects. The net effect of these changes is to reduce rate base by approximately $90,000.

Post-Test Year Plant Additions – The Company proposed an adjustment to increase South Dakota test year plant in service for projected non-revenue producing post-test year capital additions anticipated to be in service prior to October 1, 2014. The settlement determination revises the Company's adjustment to reflect actual costs for completed projects in-service as of November 6, 2014. The settlement also includes accumulated deferred income taxes on the post-test year plant additions that are reflected in rate base. The net effect of these changes is to increase rate base by approximately $423,000.

Ben French, Neil Simpson I, & Osage Retirements – BHP proposed an adjustment to remove from rate base the amounts related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Accumulated Depreciation – The Company proposed an adjustment to increase accumulated depreciation (and thereby to reduce rate base) to reflect one-half of the annual depreciation expense associated with new assets and its new depreciation rates. The settlement revises the Company's adjustment to synchronize the depreciation reserve with the plant additions that are to be included in

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rate base and to reflect a depreciation rate of 2.98% for CPGS in lieu of the Company's proposed 3.29% rate. The net effect of these changes is to increase rate base by approximately $44,000.

Cash Working Capital – BHP's proposed rate base included an allowance for cash working capital based on a lead-lag analysis. A lead-lag analysis examines the timing of the Company's receipt of service revenues from customers in relation to the Company's payment of expenses to vendors and employees. The Company's cash working capital allowance also included a rate base deduction for tax collections which the Company receives in advance of turning the related payments over to the taxing authorities. Staff carefully examined BHP's revenue lag and expense lead day determinations and made the following modifications, which are consistent with Staff adjustments in prior rate cases:

1. Revised the expense lead days for net payroll, service/holding company charges, other operating and maintenance, FICA, federal income tax, gross receipts tax, federal withholding, and sales tax;
2. Included a separate expense lead for vacation pay;
3. Included a separate expense lead for incentive compensation;
4. Included a separate expense lead for uncollectible accounts expense;
5. Revised revenue lag days to remain consistent with past Staff practice and state statute, and to more accurately reflect the South Dakota jurisdictional revenue lag; and
6. Revised expenses per day to incorporate into the lead-lag analysis the impacts of Staff's recommended adjustments to *pro forma* operating expenses.

These modifications increase rate base by approximately $5,161,000.

Rate Case Expense – Rate case expense included in Docket EL12-061, which includes costs incurred for both Docket EL12-061 and EL12-062 as of July 2, 2013, was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the Docket EL12-061 rate case expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, all amortized over a three-year period. BHP also proposed an unamortized amount of $750,046 be included in rate base. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014, for docket EL14-026 and $412,797 in actual, unrecovered costs for EL12-061 and EL12-062, for a total amount of $625,657. One-half of the rate case costs, or $369,191, is included in rate base, representing the average unamortized balance over the three year period. The net effect of these changes reduces rate base by approximately $381,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs, if any, associated with docket EL14-026 in BHP's next rate case.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the Environmental Protection Agency (EPA)'s National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In

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Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants into a regulatory asset account.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of these three generating plants over five years and include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement removes all contingencies that had been included in BHP's decommissioning estimates, revises the amount included for obsolete inventory to agree with the amount removed from working capital, amortizes the regulatory asset over ten years, and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,806,000.

Storm Atlas Regulatory Asset – Winter Storm Atlas (Atlas) occurred October 3-5, 2013, causing the worst outages in BHP's 130-year history. Heavy snow and high winds, combined with fully leafed trees, caused significant damage to BHP facilities and left as many as 41,800 customers without power. Repairing this widespread damage far exceeded BHP's normal storm-related costs. In Docket EL13-036, the Commission issued an order allowing BHP to use deferred accounting for costs incurred as a result of Atlas.

In this docket, BHP proposed to include actual costs through December 31, 2013 arising from Atlas, as well as costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection driven by Atlas. BHP proposed to amortize these costs over five years and to include the unamortized balance at the end of Year One, or four-fifths of the costs, in rate base. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only the incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years and includes the average unamortized balance over the first three years in rate base. The net effect of these changes is to decrease rate base by approximately $1,566,000.

Tax Return True-up – BHP's proposed test year allowance for income taxes included "true-up" adjustments to eliminate certain tax events that were recorded during the test year but which were related to periods prior to the test year. It is important to purge from test year operating results for transactions that relate to periods outside of the test year. Therefore, Staff accepts BHP's Tax Return True-up adjustments. Those adjustments are included in the Settlement revenue requirement determination.

NOL Adjustment – Over the past several years, bonus depreciation previously approved by Congress significantly increased BHP's annual tax deductions. The increased deductions, however, exceeded BHP's income resulting in a tax loss. Because of the tax loss position, BHP was not able to utilize all of its allowable deductions in the year they were earned. It had recorded deferred taxes relating to these tax deductions, nevertheless. The accumulated deferred taxes are used as an offset to BHP's rate base. Therefore, it was necessary to adjust BHP's rate base to reflect the unused tax deductions. BHP will now be able to utilize more of its previously unused tax deductions given the revenue increase agreed to by the Parties. The impact of this greater utilization of tax deductions on BHP's rate base has been reflected in the settlement revenue requirement. The result of recalculating this adjustment to reflect the effect of other adjustments incorporated in the settlement is to increase rate base by approximately $641,000.

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Other Working Capital – BHP proposed this rate base adjustment to accurately reflect recent investments in a spare transformer for Neil Simpson II, in spare fan motors at the Neil Simpson Complex, in critical spare parts at Cheyenne Prairie Generating Station, and in a new coal stockpile at the Neil Simpson Complex, while removing the test year inventories at the recently retired Ben French, Neil Simpson I, and Osage generating units. The settlement accepts this adjustment while modifying for actual costs and reflecting a more recent 13-month average for materials and supplies, fuel stocks, and customer advances. These modifications increase rate base by approximately $969,000.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system, and BHP proposed to amortize costs associated with the project over five years and to include the unamortized balance, or four-fifths of the cost, in rate base. The settlement reflects a reduction for accumulated deferred income taxes associated with the project, an update to actual project costs and actual contributions from joint owners, and includes the average unamortized balance, or one-half of the cost, in rate base. The result of Staff's revisions reduces rate base by approximately $399,000.

Customer Service Model – This Staff proposed adjustment reflects the rate base reduction for BHP's customer service model changes. With the Belle Fourche and Newell customer service and electric operation service centers being consolidated and moved to Spearfish and Sturgis, respectively, the Newell office is no longer needed. Removing the remaining amounts associated with the Newell office reduces rate base by approximately $9,000.

Sturgis Office & Operations Center – BHP built a new service center in Sturgis to consolidate operations and business offices into one location in the northern hills. As a result, the two existing facilities in Sturgis will be closed. The settlement removes the amounts related to these two facilities as they are no longer needed. This adjustment reduces rate base by approximately $308,000.

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses, including employee additions. The settlement includes a rate base adjustment associated with one-half of the amount of annual employee salaries charged to capital projects. This adjustment increases rate base by approximately $79,000.

Other Rate Base Reductions – The Company's filing included *pro forma* rate base reduction for: 1) the flow-through of the income tax benefit associated with the repairs deduction that should not be included in rate base; 2) deferred taxes and federal effect of the state NOL that should be removed from rate base since South Dakota does not impose a state income tax; 3) deferred tax liability associated with regulatory asset – unit of property account that should not be included in rate base since the amount in the regulatory asset – unit of property is not included in rate base; and 4) the addition of accumulated deferred income tax associated with the plant that is allocated to BHP from BHSC and BHUH because the assets allocated to BHP are included in rate base. The settlement accepts this adjustment.

OPERATING INCOME

Wages & Salaries – BHP's filing included several adjustments to test year payroll expenses. These adjustments included 1) using 01/28/2014 annualized payroll as a starting point as it was the most

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recent payroll at the time BHP completed its adjustment; 2) removing the labor costs associated with Neil Simpson I plant personnel who will have part of their time charged to power plants not owned by BHP at the Neil Simpson Complex; 3) a 2014 union wage increase of 3.25%, a 2014 non-union wage increase of 3.50%, a partial year of a 3.5% 2015 union wage increase, and a partial year of a 3.5% 2015 non-union increase; 5) adding the costs associated with open vacancies and additional employees needed for operations; and 6) removing costs associated with employee eliminations.

Staff agreed with the Company's adjustment, except for the amounts included for the 2014 non-union and 2015 union and non-union wage increases and employee additions. The settlement revises the Company's adjustment to 1) reflect a 2014 non-union wage increase of 3.25% in lieu of the Company's proposed budgeted 3.5%; 2) reflect a full year of the 2015 union wage increase of 3.25% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; 3) reflect a full year of the 2015 non-union wage increase of 3.0% in lieu of the Company's proposed partial year of a projected 3.5% wage increase; and 4) reflect employee additions for actual employees hired, including only the portion of employee salaries charged to O&M and adjusting the salaries for the 2015 wage increases. This adjustment reduces operating expenses by approximately $130,000.

Black Hills Corp. / Black Hills Utility Holdings Intercompany Charges – BHP proposed a $2.3 million adjustment to total company test year expenses for charges billed to it from Black Hills Utility Holdings (BHUH) (Adjustment H-5). Staff objected to this adjustment because it did not reflect a known and measurable change in BHP's costs; rather, it was merely BHP's estimate of future costs. Consistent with the Parties' treatment of other operating expenses, including expenses billed to BHP by BHSC, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, excluding amounts associated with vegetation management and reflecting an annualization for customer records and collection expenses associated with a change in allocation factors. The *pro forma* utility holdings costs also reflect an annualization of wage increases for both 2014 and 2015. The effect of these changes is to increase South Dakota operating expenses by approximately $527,000.

Employee Pension & Benefits Adjustment – BHP proposed a $334,319 total company adjustment to test year employee benefits expenses (Adjustment H-6). Within this adjustment, BHP normalized its test year pension expense by averaging the annual expense over the past five years. This normalization adjustment reduced the test year pension expense by $508,454 on a total company level. Staff agreed to BHP's pension expense normalization adjustment if it is to be applied consistently in future rate cases. Staff disagreed with the remainder of BHP's proposed employee benefits adjustment because it is based on estimated future costs rather than known cost changes. The settlement reflects known post-test year changes in employee benefits costs rather than BHP's estimates. It also reflects a normalized level of pension costs based on a five-year average of BHP's actual pension expense. The effect of these changes is to reduce South Dakota operating expenses by approximately $289,000.

Bad Debt Analysis – BHP proposed an adjustment to decrease bad debt expenses based on a three year uncollectible rate average. The settlement decreases bad debt expense based on a five year uncollectible rate average applied to retail revenues. The net effect of this change increases jurisdictional operating expense by approximately $6,000.

Generation Dispatch & Scheduling – BHP proposed an adjustment to update costs for generation dispatch and scheduling in accordance with the Generation Dispatch and Energy Management

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Agreement (GDEMA) which allocates costs to the parties contracting for services based on total capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year-end August 2014 costs, while allowing known and measurable increases to labor and labor overhead. Staff also corrected errors to the capacities provided for Black Hills Power and Black Hills/Colorado Electric. The result of Staff's revisions reduces jurisdictional operating expense by approximately $106,000.

Energy Cost Adjustment Expense Elimination – The Company proposed an adjustment to remove all costs that are collected through the Energy Cost Adjustment (ECA) from the test year. The settlement accepts this adjustment.

Neil Simpson Complex Shared Facilities – BHP proposed an adjustment to update revenues and expenses for shared facilities in accordance with the Neil Simpson Complex Shared Facilities Agreement which allocates revenues and expenses to the parties based on net capacity of each company. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual costs. The result of Staff's revisions reduces jurisdictional operating expense by approximately $74,000 and reduces jurisdictional operating revenue by approximately $136,000.

Removal of Unallowed Advertising – BHP proposed an adjustment to remove advertising expenses that should not be recovered from ratepayers. The settlement accepts this adjustment and further removes additional advertising costs which do not contribute to the provision of safe, adequate, and reliable electric service for South Dakota ratepayers. The effect of this adjustment reduces operating expenses by approximately $4,000.

Power Marketing Adjustment – BHP's adjustment to remove power marketing expenses from the base rate regulated cost of service is found on Statement H, Schedule H-12. The revenue adjustment found in Statement I, page 1, removes the corresponding power marketing revenues from the base rates. The settlement revises the expense adjustment to correct the labor-bonus costs removed and accepts the revenue adjustment. The effect of this adjustment reduces operating expenses by approximately $9,000.

Rate Case Expense – Rate case expense included in Docket EL12-061 (consisting of costs related to Docket EL12-061 and EL12-062) was amortized over a three-year period beginning June 16, 2013. Interim rates in this case were put into effect on October 1, 2014, leaving approximately 20.5 months of cost recovery until the expenses are completely amortized. The settlement in EL12-061 established a tracker for the potential recovery of the residual costs associated with both dockets in BHP's next rate case filing.

BHP proposed recovery of projected rate case costs for EL14-026, the remaining unamortized rate case expense from EL12-061 and EL12-062, and the residual costs related to EL12-061 and EL12-062, amortized over a three-year period. The settlement reflects a three-year amortization of $212,861 in actual costs as of November 6, 2014 for docket EL14-026 and $412,797 in actual, unrecovered amounts for EL12-061 and EL12-062, for a total three-year amortization allowance of $625,657. The net effect of these changes is a reduction in operating expenses by approximately $188,000. The settlement also establishes a tracking mechanism for the potential recovery of the residual costs associated with docket EL14-026 in the next rate case filing.

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Vegetation Management Expense – BHP proposed to adjust its test year vegetation management expenses to reflect the amount approved in the stipulation in Docket EL12-061. The settlement accepts this adjustment with a slight modification which updates the allocator to conform to what BHP filed in its Statement N. The result of Staff's revision increases jurisdictional operating expense by approximately $1,000.

CPGS O&M – The Company proposed an adjustment to reflect projected operation and maintenance expense for CPGS during a normal year. The settlement reflects the Company's proposed adjustment, less reagent costs which are recovered through the ECA. This adjustment reduces operating expenses by approximately $28,000.

Ben French Severance Expense – BHP proposed an adjustment to remove the employee severance expense associated with the Ben French plant. The settlement accepts this adjustment.

Neil Simpson Complex Common Steam Allocation – BHP proposed an adjustment to update costs for the operation and maintenance of Neil Simpson Complex common steam facilities where BHP is responsible for costs relating to the capacity associated with Neil Simpson II and its ownership percentage of Wygen III. Staff generally agreed with the adjustment but replaced the budgeted costs used by BHP with actual year end August 2014 costs, while allowing known and measurable increases to labor and benefits. Staff also corrected errors in the capacity shares provided for Black Hills Power and MDU, City of Gillette & Other. The result of Staff's revisions reduces jurisdictional operating expense by approximately $243,000.

Ben French, Osage, & Neil Simpson I O&M Elimination – BHP proposed an adjustment to remove the test year operating and maintenance expenses related to the Ben French, Neil Simpson I, and Osage power plants that were retired on or before March 21, 2014, to comply with the Environmental Protection Agency (EPA) Area Source Rules. The settlement accepts this adjustment.

Future Track Workforce Development – BHP proposed a $721,861 total company expense adjustment (Adjustment H-19) to implement its eight-year Future Track Workforce Development Program. Included in the Company's proposal was a request to defer as a regulatory asset for future recovery all costs associated with the program that exceed the amount included in base rates.

Staff objected to the Company's proposal, both as to the expense to be included in base rates and to BHP's proposal to defer expenses in the future. The Parties agreed to reflect in rates BHP's actual costs for newly hired employees under the Future Track program, without deferrals. The effect of this change is to decrease South Dakota operating expenses by approximately $344,000. The settlement also eliminates the annual reporting requirements proposed in BHP's filing.

69 kV LIDAR Surveying Project – BHP proposed this adjustment to recover Light Detection and Ranging (LIDAR) project costs on its 69 kV system. This survey provided BHP with electronic modeling data to verify proper ground clearances were met and help streamline their vegetation management efforts. The project cost is shared with the joint owners of the transmission system. BHP's share is amortized over five years to correspond with the expected frequency of the survey. Staff's adjustment reflects actual costs of the survey and actual contributions from the joint owners. The result of Staff's revision reduces jurisdictional operating expense by approximately $66,000.

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Customer Service Model Adjustment – This adjustment reflects the cost reductions BHP achieved as a result of their customer service model changes. The Belle Fourche and Newell customer service and electric operation services centers were consolidated and moved to Spearfish and Sturgis, respectively. This adjustment removes the salaries and benefits of three customer service representatives and eliminates Belle Fourche and Newell facility costs. The settlement also removes further costs associated with telephone, janitorial labor, and depreciation expense. The result of Staff's revision reduces jurisdictional operating expense by approximately $7,000.

Remove City of Gillette – BHP proposed an adjustment to remove the City of Gillette revenue as it relates to replacement energy. The associated costs are removed as part of the Power Marketing adjustment. The settlement accepts this adjustment.

Unbilled Revenue and Provision for Rate Refunds – Unbilled Revenue reflects an accounting accrual made each month to reflect a portion of the current month usage which is billed in the following month. These accrual entries are reversed out the following month. Provision for Rate Refunds reflects the balance related to interim rates in Dockets EL12-061 and EL12-062. These adjustments remove the entire per books amounts from these two accounts to reflect normal levels. The settlement accepts these adjustments.

Removal of Energy Cost Revenue – The Company proposed an adjustment to remove revenue associated with the ECA as associated energy costs were also removed from the test year. The settlement accepts this adjustment.

PIPR Rate Annualization – The test year revenues contain only a portion of the Phase In Plan Rate revenues established in Docket EL12-062. This known and measurable adjustment is needed to reflect the proper level of revenue and properly match what customers were paying at the end of the test year, thus reducing the revenue deficiency. The settlement accepts this adjustment.

Weather Normalization – BHP's filing contained a weather normalization adjustment of ($644,705). Staff undertook an independent weather normalization analysis and concluded that an adjustment of ($264,403) would be appropriate. Staff's adjustment updated BHP's data to reflect the latest NOAA weather normals for the thirty year base period 1981-2010. Staff also included June in the analysis of cooling load sensitivity, and measured sensitivity in absolute value as a departure from normal, rather than relative variation from monthly normals. Sensitivity was based on regression coefficients correlating usage with departure from normal. BHP accepted Staff's adjustment for settlement purposes. The effect of these changes increases operating revenues by approximately $380,000.

Industrial Contract Service Accrual – BHP proposed this known and measurable adjustment to properly match revenues with test year usage for three of their industrial customers on contract rates. The settlement accepts this adjustment.

EL12-061 Rate Increase Annualization – The test year revenues are based on the rates established in Docket EL09-018; however, rates were changed in Docket EL12-061, effective October 1, 2013. This is a known and measurable change to test year operating results. BHP proposed this adjustment to reflect the proper level of revenue to be received from customers based on the recently approved rates. The settlement accepts this adjustment.

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Interest Synchronization – The settlement synchronizes the tax deduction for interest expense with the weighted cost of long-term debt and the historical test year rate base as adjusted for known and measurable changes.

Depreciation Expense – In its March 31, 2014 rate filing, BHP claimed a total company depreciation expense allowance of $3,035,046 related to the Cheyenne Prairie Generating Station based on the then-estimated $92,250,624 total company plant investment at its expected in-service date of October 1, 2014. The expense allowance reflected a composite depreciation accrual rate of 3.29% that assumed a 35-year life span for the plant, allowances for retirements of plant components during the life span and an estimate of removal costs amounting to 4% of the plant investment at the time of its retirement.

The settlement reduces the CPGS depreciation allowance by $349,819 to $2,685,227, on a total company level, to reflect BHP's agreed-upon actual investment in the plant and a composite depreciation accrual rate of 2.98%. The 2.98% composite rate was derived by extending the assumed life span of CPGS from 35 years to a more realistic 40 years judging by life estimates made by other utilities for combined cycle generating units. Other parameters reflected in the 2.98% rate (interim retirements and removal costs) are consistent with the parameters reflected in BHP's existing depreciation accrual rates for its other generating facilities.

The settlement further revises the Company's depreciation adjustment to reflect the effect of the other plant adjustments included in the settlement. The net effect of these changes is to decrease South Dakota jurisdictional operating expenses by approximately $87,000.

Decommissioning Regulatory Asset – The Neil Simpson I, Ben French, and Osage coal-fired power plants are subject to the EPA's National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Area Source Rules). After evaluating the options, BHP concluded the most cost effective plan to comply with these rules was to retire Neil Simpson I, Osage, and Ben French by the compliance deadline of March 21, 2014. The decommissioning process began in 2014 and is estimated to be completed by September 2015. In Docket EL13-036, the Commission issued an order authorizing BHP to transfer the remaining plant balance for the soon to be decommissioned plants to a regulatory asset.

In this docket, BHP proposed to amortize the estimated costs associated with the retirement and decommissioning of Neil Simpson I, Ben French, and Osage over five years. The settlement removes all contingencies, revises the amount included for obsolete inventory to agree with the amount removed from working capital, and amortizes the regulatory asset over ten years, reducing the annual South Dakota amortization expense by approximately $1,651,000. BHP may track the actual costs incurred and seek recovery, in a future rate case, of decommissioning costs not recovered from customers.

Storm Atlas Regulatory Asset – BHP proposed to include its actual Atlas-related costs through December 31, 2013, and its estimated costs through the end of February 2014. The Company also proposed to include costs for a system-wide line inspection necessitated by Atlas. BHP proposed to amortize these costs over five years. The settlement reflects actual, final Atlas-related costs (excluding employee bonuses) and actual system inspection costs through September 30, 2014, and reflects only incremental internal labor costs associated with the system inspection. The settlement amortizes the regulatory asset over ten years. The net effect of these changes is to reduce the annual South Dakota amortization expense by approximately $512,000.

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Charitable Contributions – The settlement removes approximately $16,000 in charitable contributions.

Storm Damage – The settlement normalizes storm damage costs to a five-year average. As Atlas was the only major storm event in 2013 and its costs are recovered in a separate adjustment, this normalization adjustment would need to include $0.00 for the 2013 expense, and Staff was concerned that using $0.00 would not reflect an accurate value of normal storm damage expense. Thus, Staff chose the 2008 through 2012 timeframe for this adjustment and increased operating expense by approximately $31,000.

Incentive Compensation – BHP's proposed revenue requirement included approximately $3.8 million for incentive compensation, including amounts billed from the affiliate service company. For settlement purposes, the Parties agreed that incentive compensation paid for achieving financial performance goals will be excluded from BHP's South Dakota revenue requirement. This adjustment reduces South Dakota operating expenses by approximately $666,000.

Economic Development – The Company proposed 100% recovery of economic development expenses included in the test year. The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. The adjustment reduces operating expenses by approximately $27,000.

Association Dues – The settlement removes approximately $6,000 in association dues costs associated with donations, lobbying, and various other activities that do not provide for the provision of safe, adequate, and reliable electric service for South Dakota ratepayers.

Custer to Hot Springs Cooperatives Revenues – BHP has a joint ownership agreement with Rushmore Electric and its two members, Black Hills Electric Cooperative and Butte Electric Cooperative, for the co-owned portions of the 69 kV sub-transmission system. Rushmore Electric Power Cooperative, on behalf of itself and its members, pays BHP a monthly fee to ensure that customers of all parties are fairly and accurately responsible for their use of the jointly owned facilities. The settlement includes an adjustment to account for the additional annual revenues BHP will receive associated with the Custer to Hot Springs line. The effect of this adjustment is to increase operating revenues by approximately $90,000.

Workers Compensation – During discovery, BHP proposed an adjustment to normalize workers compensation costs to a five-year average of the costs. The settlement accepts this adjustment, increasing operating expenses by approximately $172,000.

Black Hills Corp./ Black Hills Service Co. Intercompany Charges – BHP's filed case included test year expenses billed to it by its affiliate service company, approximately $20.4 million, without adjustment. Consistent with the parties' treatment of other operating expenses, including expenses billed to BHP by BHUH, the Parties agreed to recognize known changes in billed costs by the service company through August 31, 2014. That is, the rate case allowance for service company billings reflect BHP's actual costs for the twelve months ended August 31, 2014, except for property insurance which is BHP's actual costs for the year October 2014 through September 2015. The pro forma service company costs also reflect an annualization of wage increases for both 2014 and 2015. The net effect of these changes is to increase South Dakota operating expenses by approximately $1,132,000.

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Income Tax Adjustment – The Company's filing included pro forma adjustments to income tax for true-up items and items that are not part of the regulated operations of BHP that should therefore not be included in the computation of federal income tax. The settlement accepts this adjustment.

COST OF CAPITAL AND RATE OF RETURN

BHP's initial filing sought an overall rate of return of 8.48 percent, which included an embedded debt cost of 6.45 percent and a capital structure of 53.32 percent equity and 46.68 percent debt. The requested rate of return on equity was 10.25 percent. Staff's analysis initially challenged all three components of the overall rate of return: (1) embedded cost of debt, (2) the capital structure, and (3) the required return on equity.

[Begin Confidential] [redacted]

[redacted]

[redacted]

[redacted]

[redacted] **[End Confidential]**, the settlement overall rate of return is 7.76 percent.

RATE DESIGN ISSUES

The parties agree in principle on all issues regarding rate design and the class revenue distribution. The settlement position reached between Staff and BHP is discussed below.

Class Cost of Service/Spread of the Increase – BHP's filed case included a class cost of service study ("CCOSS"). A CCOSS is useful in assigning revenue responsibility to each rate class that BHP serves in

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South Dakota and in designing rates within each class. The allocation methods reflected in BHP's CCOSS are basically the same as those that were reflected in previous CCOSS studies filed by BHP and accepted by Staff and the Commission. In this proceeding, however, BHP introduced the results of a new customer load study based primarily on data obtained from the Company's new AMI meters. The new load data was used in developing the class demand allocation factors used in the CCOSS. The new load data incorporated into the CCOSS indicated that base rates for two of the five customers classes should be increased significantly (Residential – 19.26% and General Service Large/Industrial Contract – 15.44%); base rates to the Water Pumping/Irrigation class should be increased by a small amount (3.45%); and base rates for the remaining two classes should be decreased (General Service – 6.37% and Lighting Service – 15.74%). Rather than implementing these indicated rate changes, BHP proposed a rate moderation plan to avoid adverse rate impacts to the Residential and General Service Large/Industrial Contract customers. Under BHP's moderation plan, no class is to pay less than 75 percent of the system-wide percentage increase and no class is to pay more than 120 percent of the system-wide percentage increase.

Without agreeing specifically with either the results of the CCOSS or BHP's underlying new load research results, the Parties agreed to accept BHP's proposed rate moderation plan by implementing a 75% to 120% percent collar around the system-wide percentage increase. Under this approach, the following class increases result:

Settlement Class Revenue Increases

Class	Percent Increase
Residential	5.04%
General Service	3.46%
General Service Large/Industrial Contract	4.55%
Water Pumping/Irrigation	3.11%
Lighting Service	3.45%
Total	**4.35%**

Rate Design (Residential Customer Service Charge) – BHP's currently effective monthly customer service charge for the Residential class is $8.75. BHP proposed to increase the present rate to $10.00. In settlement, the parties agreed to increase the Residential monthly customer service charge to $9.25. This represents a 5.71 percent increase in that charge, which is within the range agreed to among the parties for the Residential class as a whole. Staff also believes that a $9.25 monthly service charge is supported by the underlying costs to serve Residential customers.

OTHER ISSUES

Economic Development – The settlement reflects a $100,000 economic development plan, inclusive of labor, to be split 50/50 between shareholders and ratepayers. Under the terms of the settlement the following conditions apply:

- $100,000 total paid equally by ratepayers ($50,000) and shareholders ($50,000);

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- Expenses shall include but not be limited to, all South Dakota labor, expenses and monetary contributions deemed to be a benefit to economic development in the BHP South Dakota electric territory;
- On an annual basis, no later than March 1 of each year, BHP will submit for the Commission's approval a filing that describes the actual cost, design and individual benefits of each cost to BHP's Economic Development programs in the previous calendar year and the projected cost, design and individual benefits of each cost to BHP's Economic Development programs in the current calendar year;
- The Commission may determine that some of the programs are not appropriate for purposes of 50% rate recovery;
- If the remaining programs cost less than $100,000 at the end of a program year, the unspent costs shall be "carried over" into the next program year for Commission approval of expenditure or refund; and
- No carry-over shall occur for any amounts spent annually in excess of $100,000.

Energy Cost Adjustment – The Company proposed the following change to the Fuel and Purchased Power Adjustment (FPPA), which is a component of the ECA: 1) to include any difference in ad valorem or property taxes from what is reflected in base rates; 2) to credit 100% of the Company's wholesale contract revenue on October 1, 2014, as agreed to in Docket No. EL12-062; 3) to eliminate the power marketing credit minimum; and 4) to recover 100% of the costs related to short-term planning reserve capacity purchases and sales. Staff agreed with items 1, 2, and 4, but took issue with the elimination of the power marketing credit minimum. The Parties agreed for settlement purposes to reduce the power marketing credit minimum from $2 million to $1 million and increase the power marketing sharing from 65% to 70%.

Major Maintenance Accrual – BHP requested approval of a modification to the major maintenance account to expense a portion of the plant overhaul costs each year based on a plant's planned maintenance cycle. In Docket EL09-018, the settlement allowed BHP to establish a major maintenance account and a regulatory liability for steam plant maintenance and a 7-year cycle was established. The work previously done during the seven year overhaul is now split into two overhauls. There is no change in the existing accrual at this time. The settlement defines major maintenance for steam plants as the expenses incurred during the period of time when a steam turbine generator is opened for maintenance.

Implementation of Rates – The tariffs shown on Exhibit 1 attached to the Settlement are to be implemented for service rendered on or after March 1, 2015. Customer bills will be prorated so that usage prior to October 1, 2014, is billed at BHP's previously effective rates (i.e., the base rate in effect immediately prior to the interim rates implemented on October 1, 2014), and usage on and after October 1, 2014, is to be billed at the new rates established by the settlement.

Interim Rate Refund – Interim rates were implemented on October 1, 2014. Approval of the Settlement will authorize a rate increase less than the interim rate level. The Company agrees to refund customers the difference between interim rates and new rates established by the settlement for usage during the period October 1, 2014 through February 28, 2015. As part of the refund, BHP will include interest, calculated by applying a 7% annual interest to the average refund balance for each month that interim revenues were collected. The Company's Interim Rate Refund Plan is attached to the Settlement as Exhibit 3.

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Contract with Deviations – On September 4, 2014, BHP filed a Contract with Deviations between BHP and SDSTA. The Commission approved this Contract with Deviations on an interim basis. Now that the cost of service and class cost of service study review is complete, Staff and BHP agree the Contract with Deviations may now be finally approved by the Commission, without condition.

RECOMMENDATION

Staff recommends the Commission approve the Settlement for the reasons stated above.

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Sept 05 2023

AUTHORIZED ROE AND INTEREST RATES: DUKE ENERGY CAROLINAS

Description	Dates (filing and Final Order)	ROE	30-Year Treasury Yield	
			30-Day Average	Projected
Current case, E-7, Sub 1276	Filed: Jan. 19, 2023	ROE requested: 10.4%	3.70%	3.90%
	As of: Aug 22, 2023		4.13%	3.92%
2019 case, E-7, Sub 1214	Filed: Sept 30, 2019	ROE authorized: 9.6%	2.11%	2.38%
	Final Order: Mar 31, 2021		2.31%	2.23%
2017 case, E-7, Sub 1146	Filed: Aug 25, 2017	ROE authorized: 9.9%	2.83%	3.35%
	Final Order: June 22, 2018		3.10%	3.48%
2013 case, E-7, Sub 1026	Filed: Feb 4, 2013	ROE authorized: 10.2%	3.06%	3.25%
	Final Order: Sept 24, 2013		3.81%	3.95%
2011 case, E-7, Sub 989	Filed: July 1, 2011	ROE authorized: 10.5%	4.24%	4.73%
	Final Order: Jan 27 2012		3.00%	3.45%

Sources: Federal Reserve, Blue Chip Financial Forecasts (various dates)

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Aug 03 2023

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 222

Docket No. E-7, Sub 1276

Date of Request: **July 3, 2023**
Date of Response: **July 13, 2023**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 222-8, was provided to me by the following individual(s): Ginny Boucher, Director of Rate & Regulatory Planning, was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 222
DEC Docket No. E-7, Sub 1276
Item No. 222-8
Page 1 of 1

Oct 05 2023

Request:

8. Using 2021 as an example year, please provide the following:

   A. The weather-normalized earnings;

   B. Whether those weather-normalized earnings exceeded the authorized rate of return on equity;

   C. Whether those weather-normalized earnings exceeded the authorized rate of return on equity plus 50 basis points;

   D. The exclusions that would be made (if any) from any penalties or rewards from PIM incentives and any incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f); and

   E. The data, facts, formulas, methodology, rationale, assumptions, base, ratios, additions, subtractions, etc. that were utilized in providing the requested information.

Response:

Please see attached example. In the excel spreadsheet "PSDR 222 ESM example 2021 and test years" tab "2021 ESM Weather Normal" shows only the weather adjustment for 2021. The weather adjusted ROE for 2021 did not exceed authorized ROE plus 50 basis points so no return to customers is calculated.

Other adjustments to be included for 2021 under the ESM calculation include removal of incentives related to demand-side management and energy efficiency; removal of margin from EV sales and depreciation annualization. These additional adjustments along with the weather adjustment are shown on tab "2021 ESM All adjs". Including the weather adjustment, the DSM/EE adjustment and depreciation annualization adjustment results in an ROE that does not exceed the authorized ROE plus 50 basis points, so no return to customers is shown. Please note that this is a theoretical example only as we were not subject to earnings sharing for the twelve months ended 2021. In addition, 2021 in this example is not adjusted for known and measurable adjustments made in a rate case.

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DUKE ENERGY CAROLINAS, LLC
EARNINGS SHARING MECHANISM CALCULATION
DOCKET NO. E-7 Sub 1276
PSDR 222-8
Duke Energy Carolinas, LLC
Electric Operating Experience - NC Retail
12 Months Ended December 31, 2021
Dollars in Thousands

Line No.	Description	NC Retail Regulatory Per Books (Col. 1)	Pro-Forma Adjustments (Col. 2)	As Adjusted (Col. 3)
1	Operating Revenues	$ 4,823,446	$ (55,596)	$ 4,767,849
2	Operating Expenses			
3	O&M Expenses - Fuel and Purchase Power	1,077,957	891	1,078,848
4	O&M Expenses - Other	1,202,231	110	1,202,341
5	Depreciation & Amortization Expenses	1,030,336	(3,988)	1,026,347
6	Taxes Other Than Income	213,688	-	213,688
7	Income Taxes	23,955	(12,284)	11,670
8	Investment Tax Credit	(2,647)	81	(2,566)
9	Total Operating Expenses	3,545,519	(15,190)	3,530,329
10	Net Operating Income Net of Interest on Customer Deposits	1,277,926	(40,406)	1,237,521
11	Rate Base			
12	Plant in Service	$ 31,452,786	$ -	$ 31,452,786
13	Accumulated Provision for Depreciation	(11,905,955)	-	(11,905,955)
14	Accumulated Deferred Income Taxes	(2,620,215)	-	(2,620,215)
15	Operating Reserves	(153,889)	-	(153,889)
16	Working Capital	1,029,679	-	1,029,679
17	Total Rate Base	$ 17,802,406	$ -	$ 17,802,406

NC Retail As Adjusted ESM Revenue Requirement

		Capital (Col. 1)	Ratio (Col. 2)	Rate Base (Col. 3)	Cost Rate % (Col. 4)	Operating Income (Col. 5)
18	Long-term debt	$ 12,260,955	46 89%	$ 8,347,243	4.27%	$ 356,011
19	Members' equity	13,888,337	53.11%	9,455,163	9.32%	881,510
20	Total	$ 26,149,292	100 00%	$ 17,802,406		$ 1,237,521
21	Authorized ROE					9.60%
22	ESM ROE Threshold (Line 21 + 50 basis points)					10.10%
23	Realized Adjusted ROE (Line 19, Col 4)					9.32%
24	Basis Points above ESM Threshhold (If Line 23< line 22, then 0, else Line 23 - Line 22)					0.00%
25	Operating income to be shared (Line 24 x Line 19, Col 3)					-
26	Gross-up for Income Taxes					-
27	Revenue to be shared (Line 25 + Line 26)					$ -

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DUKE ENERGY CAROLINAS, LLC
EARNINGS SHARING MECHANISM CALCULATION
DOCKET NO. E-7 Sub 1276

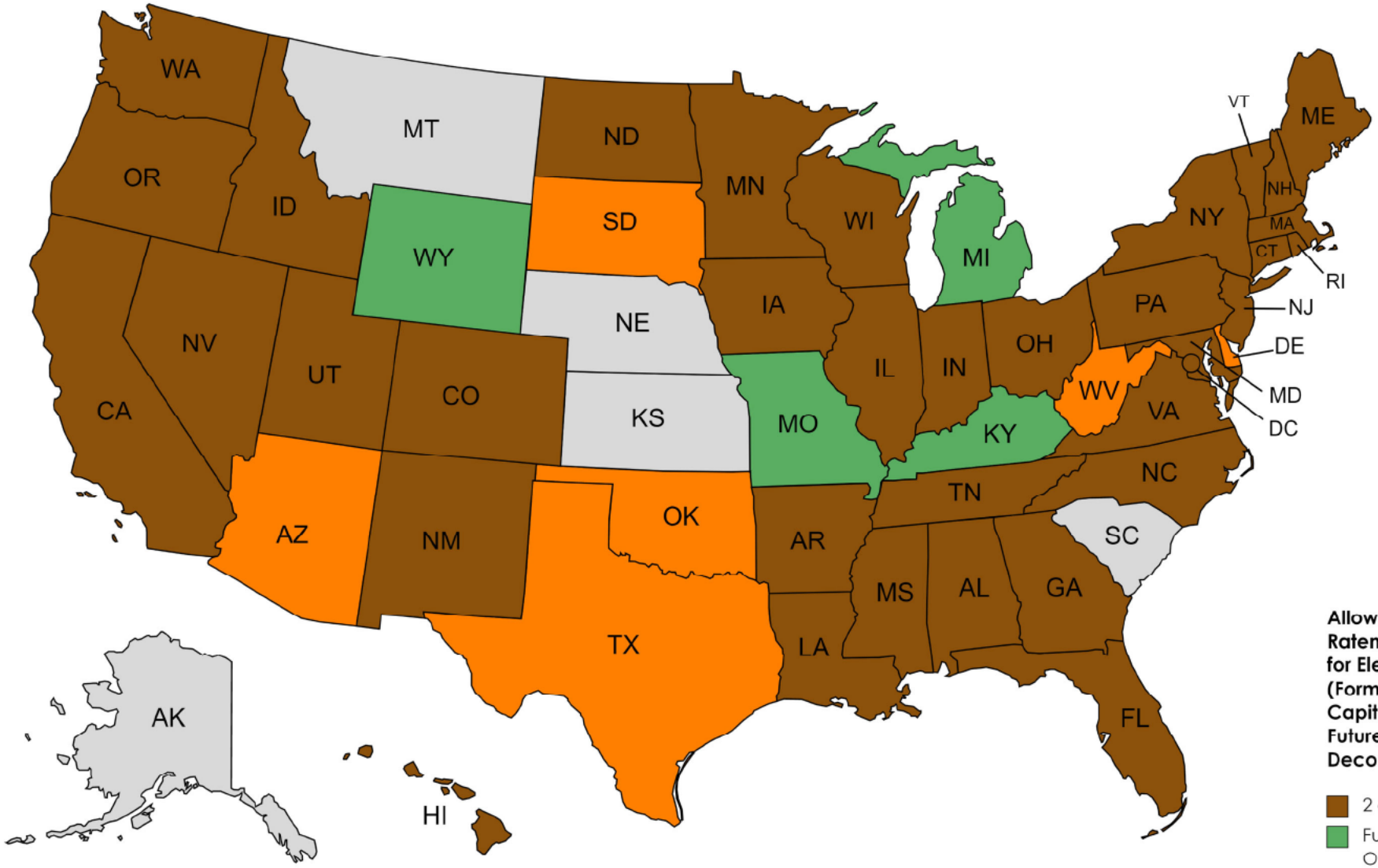
Duke Energy Carolinas, LLC
Electric Accounting & Pro Forma Adjustments
NC Retail
12 Months Ended December 31, 2021
Dollars in Thousands

Line No.	Description	Operating Revenue	O&M Fuel and Purchase Power	O&M All Other	Deprec. & Amort. Expense	Taxes Other Than Income	Income Tax	Investment Tax Credit
1	Weather Normalization	$ 4,807	$ 891	$ 110	$ -	$ -	$ 889	$ -
2	Electric Vehicle Sales	-	-	-	-	-	-	-
3	DSM/EE Incentives - ES-1 Return	(60,403)	-	-	-	-	$ (14,104)	-
4	PIMS	-	-	-	-	-	-	-
5	Depreciation Annualization	-	-	-	(3,988)	-	931	81
6		-	-	-	-	-	-	-
7		-	-	-	-	-	-	-
8		-	-	-	-	-	-	-
9		-	-	-	-	-	-	-
10		-	-	-	-	-	-	-
11		-	-	-	-	-	-	-
12		-	-	-	-	-	-	-
13		-	-	-	-	-	-	-
14		-	-	-	-	-	-	-
15		-	-	-	-	-	-	-
16	**TOTAL - ALL PRO FORMAS**	**$ (55,596)**	**$ 891**	**$ 110**	**$ (3,988)**	**$ -**	**$ (12,284)**	**$ 81**

Line No.	Description	Plant in Service	Accum Prov for Depreciation	Accumulated Deferred Inc Tax	Operating Reserves	Working Capital
17	Weather Normalization	$ -	$ -	$ -	$ -	$ -
18	Electric Vehicle Sales	-	-	-	-	-
19	DSM/EE Incentives	-	-	-	-	-
20	PIMS	-	-	-	-	-
21	Depreciation Annualization	-	-	-	-	-
22		-	-	-	-	-
23		-	-	-	-	-
24		-	-	-	-	-
25		-	-	-	-	-
26		-	-	-	-	-
27		-	-	-	-	-
28	**TOTAL - ALL PRO FORMAS**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Map of Allowed Alternative Ratemaking Mechanisms for Electric Utilities (Formula Rates, MYRPs, Capital Trackers, Future Test Years, and Decoupling), prepared by Duke Energy from Various Sources, May 2023

I/A



Created with mapchart.net

Note: There were no states that allowed formula rates only, MYRPs only, or decoupling only, without also allowing other mechanisms, and so these states were coded as 2 or More Mechanisms.

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DEP Late-Filed Exhibit No. 11 Docket No. E-2, Sub 1300

Narrative Accompanying Map of Allowed Alternative Ratemaking Mechanisms for Electric Utilities

DEP Late-Filed Exhibit No. 11 illustrates those states that have in place various forms of Alternative Ratemaking Mechanisms.

Summary of Alternative Ratemaking Mechanisms

DEP Late-Filed Exhibit No. 11 reflects those states in which one or more Alternative Ratemaking Mechanism is allowed by law, currently in place, or had been previously approved for an electric utility in the state. The following list summarizes the broad categories of Alternative Ratemaking Mechanisms:

- **Formula Rates** – Mechanism that allows for an annual true-up of the utility's costs to be reflected in customer rates. Formula rates vary from state to state but are often comprehensive in scope and provide more certainty of recovery of actual costs than other mechanisms. Also, because formula rates are often comprehensive in scope, in some cases, they render other mechanisms, like decoupling, unnecessary or duplicative.

- **Multiyear Rate Plan (MYRP)** – Mechanism that allows for annual adjustments to rates by fixed step-ups, an index or formula, or a combination of both. MYRPs vary from state to state and can allow for rate increases based on a variety of factors, including but not limited to capital, Operations and Maintenance ("O&M") or both. North Carolina's MYRP only allows for forecasted capital for specific projects and the associated net O&M costs.

- **Future Test Year** – Mechanism that sets rates based on either a partially or fully forecasted test year. A forecasted test year captures the full projected changes in both capital and O&M. North Carolina does not permit an electric utility to base rates on a fully forecasted test year.

- **Trackers for Grid or Other Capital Investments** – Mechanism that allows for annual recovery of actual costs for capital investments in between rate cases.

- **Decoupling** – Mechanism that breaks the link between a utility's volume of sales and revenue. DEP Late-Filed Exhibit No. 11 excludes states that only had a lost revenue adjustment mechanism for Demand Side Management and Energy Efficiency related lost sales.

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DEP Late-Filed Exhibit No. 11 Docket No. E-2, Sub 1300

Supporting Information

The primary sources of information underlying DEP Late-Filed Exhibit No. 11 are:

Potential Cross Exhibits:

- Public Staff's Potential Cross Exhibit No. 10, "Adjustment clauses: A state by state overview," S&P Global Market Intelligence (July 18, 2022)
- Public Staff's Potential Cross Exhibit No. 12, "Alternative regulation provisions in place (as of March 31, 2020) - Corrected," S&P Global Market Intelligence (March 31, 2020)
- CUCA Potential Cross Exhibit No. 4, "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," Pacific Economics Group Research, LLC (January 2013)

Other summary documents:

- "Decoupling to Support NERP Goals: What is it, How to do it," Regulatory Assistance Project ("RAP") presentation on decoupling (April 2, 2020)
- Alternative ratemaking plans in the U.S., S&P Global Market Intelligence (April 16, 2020)

Other sources of information:

- Witness Bateman also relied on her own expertise regarding knowledge of other states in which Duke Energy Progress, LLC affiliates operate, as well as in consultation with Pacific Economics Group, a leading expert in alternative regulation and performance-based ratemaking.

Modern cost recovery mechanisms by state

Brown	2 or more
Green	Future Test Year
Orange	Trackers
Gray	No Mechanism

Note: No state had only 1 of the other mechanisms in place.

State	Future test period	MYRP or formula rates	Trackers for grid or other capital investments	Decoupling	Notes	Color for Map
Alabama	Yes	Formula Rates	Yes		Rate CNP addresses the costs of various plant additions including generating facilities and investments made to comply with laws, regulations, or other government mandates	Brown
Alaska						Gray
Arizona			Yes	LRAM	Trackers have been approved for new generation, renewable generation, and environmental compliance over the years.	Orange
Arkansas	Partially forecast	Formula Rates		LRAM	Formula Rate Plans may use forecasted test years. Trackers have been approved for new generation and environmental compliance.	Brown
California	Yes	MYRP	Yes	Yes	CA utilities have a plethora of capital cost trackers to address many kinds of investments, including system resilience.	Brown
Colorado			Yes	Yes		Brown
Connecticut	Yes	MYRP	Yes	Yes	Connecticut Light & Power and United Illuminating have had MYRPs in the past 5 years and CT is developing a new PBR framework that will include an MYRP.	Brown
Delaware			Yes		DSICs have been authorized by statute, but have not been actually used. Delmarva Power & Light also has a tracker for facility relocations.	Orange
District of Columbia	Partially forecast	Formula Rates (per PEG)	Yes	Yes	A mechanism called a multiyear rate plan has been approved for Potomac Electric Power. However, due to extensive reconciliation provisions that would largely true up actual and allowed costs, PEG considers this to be a formula rate plan.	Brown
Florida	Yes	MYRP	Yes		Tampa Electric and several other Florida utilities have a tracker to address the costs of their storm protection plan (e.g., system resilience). Florida utilities often have trackers to address the costs of new generating facilities.	Brown
Georgia	Yes	MYRP			Georgia Power has trackers to address the cost of constructing new nuclear generating facilities and environmental compliance.	Brown
Hawaii	Yes	MYRP	Yes	Yes (per RAP)	Capital cost trackers available to the HECO companies include the Exceptional Project Recovery Mechanism and the Renewable Energy Infrastructure Program Surcharge.	Brown
Idaho	Partially forecast			Yes		Brown

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State	Future test period	MYRP or formula rates	Trackers for grid or other capital investments	Decoupling	Notes	Color for Map
Illinois	Yes	Formula Rates (Ameren & ComEd)		Yes	Illinois power distributors are at a unique point between formula rate plans. Both utilities' FRPs ended at the end of last year. They have filed for a "multiyear rate plan" which has similar incentives to a formula rate that would begin next year.	Brown
Indiana	Yes		Yes	LRAM		Brown
Iowa	Yes		Yes (per S&P Global report 6/22			Brown
Kansas				LRAM		Gray
Kentucky	Yes			LRAM		Green
Louisiana	Yes	MYRP and Formula Rates	Yes		Utilities have various approaches to ratemaking in Louisiana. Cleco has operated under a series of multiyear rate plans, while Entergy New Orleans and Southwestern Electric Power have tended to operate under formula rate plans.	Brown
Maine	Yes	Recent MYRP (per S&P Global as of March 2020)		Yes	Central Maine Power has operated under three separate MYRPs during the past 30 years.	Brown
Maryland	Partially forecast	Formula Rates (per PEG)	Yes	Yes	Mechanisms called multiyear rate plans have been approved for several utilities in Maryland. However, due to extensive reconciliation provisions that would largely true up actual and allowed costs, PEG considers these to be formula rate plans.	Brown
Massachusetts		MYRP	Yes	Yes	Approved trackers address the costs of grid modernization and solar generation.	Brown
Michigan	Yes			Yes (per S&P Global report)	Michigan Act 341 of 2016 explicitly stated that the Commission was allowed to authorize performance-based regulation including MYRPs.	Green
Minnesota	Yes	Recent MYRP (per S&P Global and NERP)	Yes	Yes	Northern States Power operated under a multiyear rate plan for several years in the past decade and has requested a new plan. Minnesota utilities have trackers to address the cost of transmission and renewable generation projects.	Brown
Mississippi	Yes	Formula Rates				Brown
Missouri	Partially forecast			Explicitly authorized by law		Green
Montana				Pending	Revenue decoupling mechanism implementation has been delayed due to COVID-19.	Gray
Nebraska					All of the state's utilities are non-IOUs and are not regulated at the state level.	Gray

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State	Future test period	MYRP or formula rates	Trackers for grid or other capital investments	Decoupling	Notes	Color for Map
Nevada		MYRP & formula rates explicitly authorized by law (per PEG)	Yes	LRAM	Legislation passed explicitly allowing MYRP or formula rates. The approved capital cost tracker addresses the costs of implementing natural disaster protection plans (e.g., system hardening).	Brown
New Hampshire		MYRP	Yes	Yes	Several utilities have had cost trackers to address the costs of reliability enhancement plans.	Brown
New Jersey	Partially forecast		Yes	LRAM		Brown
New Mexico	Yes		Explicitly authorized by law	Explicitly authorized by law	Legislation passed in 2020 allowing the use of capital cost trackers to address the costs of T&D grid modernization. A renewable energy rider is in place for PSNM that addresses the costs of the Company's renewable portfolio compliance costs, including the costs of the company's own renewable generation.	Brown
New York	Yes	MYRP		Yes		Brown
North Carolina		MYRP explicitly authorized by law		Explicitly authorized by law		Brown
North Dakota	Yes		Yes			Brown
Ohio	Partially forecast	MYRP	Yes	Yes		Brown
Oklahoma			Yes	LRAM		Orange
Oregon	Yes		Yes	Yes (per RAP NERP Presentation)	PacifiCorp has received approval of a capital cost tracker for wildfire mitigation.	Brown
Pennsylvania	Yes	MYRP explicitly authorized by law	Yes	Yes (per RAP NERP Presentation)		Brown
Rhode Island		MYRP	Yes	Yes		Brown
South Carolina				LRAM		Gray
South Dakota			Yes	LRAM		Orange
Tennessee	Yes		Yes		Kingsport Power received approval of a capital cost tracker to address costs resulting from a targeted reliability plan.	Brown
Texas			Yes			Orange
Utah	Yes		Yes			Brown
Vermont		MYRP	Yes	Yes (per RAP NERP Presentation)	As part of its current MYRP, Green Mountain Power is eligible to receive supplemental funding for capital additions resulting from "new initiatives", an updated cybersecurity plan, and unexpected circumstances and strategic opportunities that provide material benefit to customers.	Brown

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State	Future test period	MYRP or formula rates	Trackers for grid or other capital investments	Decoupling	Notes	Color for Map
Virginia		Recent MYRP	Yes		VEPCO has a tracker to address the costs of undergrounding feeders. Many trackers have been approved to address the cost of new generating facilities.	Brown
Washington		MYRP		Yes	Puget Sound Energy has had one approved MYRP in the past 10 years and recent legislation mandates the filing of rate plans with 2 to 4 year terms.	Brown
West Virginia			Yes			Orange
Wisconsin	Yes	MYRP			Madison Gas & Electric and Wisconsin Electric Power recently received approval of trackers to address the cost of generation additions between rate cases.	Brown
Wyoming	Yes					Green

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Altreg Precedents Amongst Duke Energy Carolinas' Proxy Group

Note: This analysis does not include FERC jurisdiction formula rates. Most utilities, including DEC, have transmission formula rates for their FERC jurisdiction. This table reports specific mechanisms or actions taken by regulators based on Pacific Economics Group's review of regulatory precedents rather than any analysis of state law.

		Current Multiyear Rate Plan?	Retail Formula Rate Plan	Forward Test Year	Wires Infrastructure Capital Cost Tracker	Generation Capital Cost Tracker	Revenue Decoupling Mechanism	Comments
DEC's NC mechanisms	**NC**	**Pending**					**Pending**	
Proxy Group		9	5	19	13	15	8	

	Holding Company	Jurisdictions	Multiyear Rate Plan	Retail Formula Rate Plan	Forward Test Year	Wires Infrastructure Capital Cost Tracker	Generation Capital Cost Tracker	Revenue Decoupling Mechanism	Comments
1	Alliant Energy	IA, WI			Yes (e.g., Interstate Power & Light and Wisconsin Power & Light)		Yes (e.g., Interstate Power & Light)		
2	American Electric Power	AR, IN, KY, LA, MI, OH, OK, TN, TX, WV, VA	Yes (e.g., Appalachian Power and Wheeling Power)	Yes (e.g., Southwestern Electric Power in Arkansas, Louisiana)	Yes (e g., Indiana-Michigan Power, Kingsport Power)	Yes (e.g., AEP-Ohio, AEP-Texas)	Yes (e.g., Appalachian Power)		
3	Ameren	IL, MO		Recent formula rate plan for Ameren Illinois	Partially Forecast (e.g., Ameren Missouri)				Ameren Illinois has requested approval of a mechanism called a "multiyear rate plan" that is very similar to its recently expired formula rate plan.
4	Avista	ID, WA, AK	2-Year Rate Plan (e g., Avista in Washington State)		Yes (e.g., Avista in Washington State)		Yes (e.g., Avista in Washington)	Yes (Avista in Idaho, Washington)	A recent rate plan approved for Avista featured multiple forward rate years. Recent legislation requires the filing of MYRPs in rate cases.
5	Black Hills	CO, SD, WY				Yes (e.g., Black Hills Colorado Electric)	Yes (e.g., Black Hills Colorado Electric)		CO has approved MYRPs for Xcel and Wyoming PUC has approved future test years for Pacificorp.
6	CenterPoint Energy	IN, TX				Yes (e.g., CenterPoint Energy Houston Electric)	Yes (e.g., Southern Indiana Gas & Electric)		Indiana law allows utilities to file a forward test year.
7	CMS Energy	MI			Yes				
8	DTE Energy	MI			Yes				
9	Dominion Energy	VA, SC, NC	Recent multiyear rate plan for Virginia Electric Power			Yes (e g., Virginia Electric Power)	Yes (e.g., Virginia Electric Power)		
10	Edison International	CA	Yes		Yes	Yes		Yes	

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	Holding Company	Jurisdictions	Multiyear Rate Plan	Retail Formula Rate Plan	Forward Test Year	Wires Infrastructure Capital Cost Tracker	Generation Capital Cost Tracker	Revenue Decoupling Mechanism	Comments
11	Entergy	AR, LA, MS, TX		Yes (e.g., Entergy Arkansas, Entergy Mississippi, Entergy Louisiana, Entergy New Orleans)	Yes (e.g., Entergy Mississippi)	Yes (e.g., Entergy Louisiana)	Yes (e g., Entergy Louisiana)		
12	Evergy	KS, MO			Partially forecasted (e.g., Evergy Metro in Missouri, formerly Kansas City Power & Light)				
13	Eversource Energy	CT, MA, NH	Yes (e.g., Eversource Energy MA)		Yes (e.g., Connecticut Light & Power)	Yes (e.g., Eversource Energy MA)		Yes (e g., Eversource Energy MA)	
14	FirstEnergy	OH, NJ, PA, WV, MD, NJ, NY	Yes (e.g., Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison)		Yes (e.g., Pennsylvania Electric, Pennsylvania Power)	Yes (e.g., Pennsylvania Electric, Cleveland Electric Illuminating)			
15	IDACORP	ID, OR			Partially Forecast		Yes (Idaho only)	Yes (Idaho only)	
16	NorthWestern Corp	MT, SD						Pending	Revenue decoupling mechanism start was delayed due to Covid-19
17	OGE Energy	AR, OK		Recent in Arkansas	Recent in Arkansas	Yes in Oklahoma	Recent in Oklahoma		Arkansas allows forward test years in the context of formula rate plans.
18	Otter Tail	MN, ND, SD			Yes in Minnesota and North Dakota	Yes in all states	Yes in all states	Yes in Minnesota	Minnesota law allows any public utility to propose a multiyear rate plan.
19	Portland General	OR			Yes		Yes	Recent	Portland General Electric's RDM recently expired, but the issue has been brought up in the Company's current rate case.
20	Sempra Energy	CA, TX	Yes (e g., San Diego Gas & Electric)		Yes (e.g., San Diego Gas & Electric)	Yes (e.g., Oncor Electric Delivery)	Yes (e.g., San Diego Gas & Electric)	Yes (e.g., San Diego Gas & Electric)	
21	Southern Company	AL, GA, MS	Yes (e.g., Georgia Power)	Yes (e g., Alabama Power, Mississippi Power)	Yes (e.g., Georgia Power)	Yes (e.g., Alabama Power)	Yes (e.g., Georgia Power)		
22	WEC Energy Group	WI, MI			Yes (e g., Wisconsin Electric Power)		Yes (e.g., Wisconsin Electric Power)		
23	Xcel Energy	CO, MI, MN, NM, ND, SD, TX, WI	Yes (e g., Northern States Power-MN in Minnesota)		Yes (e.g., Northern States Power- WI)	Yes (e.g., Northern States Power-MN in Minnesota)	Yes (e.g., Northern States Power-MN in Minnesota)	Yes (e g., Public Service of Colorado)	

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North Carolina Sustainable Energy Association

Request:

2-1. Please identify utilities that are permitted to securitize a coal plant's net book value prior to retirement, or have stopped recovery on a coal plant while it was still operational in order to inflate the net book value at retirement that could be securitized.

Response:

While preparing initial testimony, NCSEA did not research other utilities that are permitted to securitize a coal plant's net book value prior to retirement, or have stopped recovery on a coal plant while it was still operational in order to inflate the net book value at retirement that could be securitized.

Person(s) Responsible for Response; Ethan Blumenthal, NCSEA, Regulatory Counsel, N.C. Bar No. 53388

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1243
DOCKET NO. E-2, SUB 1262

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Issuance of Storm Recovery Financing Orders	))))	DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S JOINT PETITION FOR FINANCING ORDERS

Oct 05 2023

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (individually, each a "Company" and collectively the "Petitioners" or the "Companies") pursuant to North Carolina General Statute ("N.C. Gen. Stat.") § 62-172 ("SB 559" or the "Securitization Statute"),[1] and respectfully petition the North Carolina Utilities Commission ("Commission") to grant authorization for the financing of the Companies' storm recovery costs due to storm recovery activities required as a result of Hurricanes Florence, Michael, Dorian, and Winter Storm Diego (collectively, the "Storms") as a cost-saving measure for the benefit of the Companies' customers. As explained herein, the Companies estimate that securitization of the respective storm recovery costs will result in expected customer savings of 32% for DEC customers and 33% for DEP customers.

Further, the Companies request that the Commission find that their storm recovery costs[2] and related financing costs are appropriately financed by debt secured by storm

[1] Senate Bill 559, An Act to Permit Financing for Certain Storm Recovery Costs, S.L. 2019-244.
[2] The "storm recovery costs" consist of DEC and DEP's incremental operation and maintenance ("O&M") expenses deferred as regulatory assets, as well as the associated capital investments incurred during the Storms and accrued carrying charges as presented in Docket No. E-7, Sub 1214 and Docket No. E-2, Sub 1219, which were deemed reasonable and prudent in Public Staff testimony and acknowledged as such

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recovery property, and that the Commission issue orders for DEC and DEP by which each utility may accomplish such financing using a securitization structure authorized by SB 559 ("Financing Orders"), so that the Companies may recover their prudently incurred storm recovery costs. As required by N.C. Gen. Stat. § 62-172 and detailed herein, the financing of the Companies' storm recovery costs through the issuance of storm recovery bonds and the imposition and collection of storm recovery charges are expected to provide quantifiable benefits to customers as compared to the costs that would be incurred absent the issuance of storm recovery bonds and the structuring and pricing of storm recovery bonds is reasonably expected to result in the lowest storm recovery charges consistent with market conditions at the time the storm recovery bonds are priced and the terms set forth in the applicable financing order (the "Statutory Cost Objectives").

In support of this Petition, DEC and DEP state the following:

INTRODUCTION

1. Petitioners' names and addresses are:

Duke Energy Carolinas, LLC
P.O. Box 1321 (DEC 45A)
Charlotte, North Carolina 28201

and

Duke Energy Progress, LLC
P.O. Box 1551
Raleigh, North Carolina 27602

in each Company's Agreement and Stipulation of Partial Settlement with the North Carolina Utilities Commission Public Staff ("Public Staff").

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2. The names and addresses of Petitioners' attorneys are:

Lawrence B. Somers
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Duke Energy Corporation
P.O. Box 1551/NCRH 20
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Kristin M. Athens
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(919)-835-5909
kathens@mcguirewoods.com

3. Copies of all pleadings, testimony, orders, and correspondence in this proceeding should be served upon the attorneys listed above.

4. DEC is: (1) a limited liability company duly organized and existing under the laws of the State of North Carolina; (2) duly authorized by its Articles of Organization to engage in the business of generating, transmitting, distributing, and selling electric power and energy; (3) a public utility under the laws of North Carolina, and its operations in this State are subject to the jurisdiction of this Commission; (4) an investor-owned public utility; (5) a public utility under the laws of the State of South Carolina, and its operations

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in South Carolina are subject to the jurisdiction of the Public Service Commission of South Carolina; and (6) a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. DEC's service area covers 24,000 square miles in the central and western portions of North Carolina and western South Carolina. The service area includes 62 counties, 44 in North Carolina and 18 in South Carolina. The Company supplies retail electric service to approximately 2 million customers in North Carolina.

5. DEP is (1) a limited liability company duly organized and existing under the laws of the State of North Carolina; (2) duly authorized by its Articles of Organization to engage in the business of generating, transmitting, distributing, and selling electric power and energy; (3) a public utility under the laws of North Carolina, and its operations in this State are subject to the jurisdiction of this Commission; (4) an investor-owned public utility; (5) a public utility under the laws of the State of South Carolina, and its operations in South Carolina are subject to the jurisdiction of the Public Service Commission of South Carolina; and (6) a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. DEP's service area covers 32,000 square miles including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville, and an area in the northeastern portion of South Carolina. The Company supplies retail electric service to approximately 1.4 million customers in North Carolina.

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THE STORMS

6. On September 14, 2018, Hurricane Florence made landfall near Wrightsville Beach, North Carolina with maximum wind gusts exceeding 105 miles per hour and storm surges in the range of 9 to 13 feet. The flooding and wind damage from Florence caused substantial damage to the transmission and distribution systems of DEC and DEP and resulted in electrical outages across virtually the entire eastern half of North Carolina, directly impacting the Companies' service territories. The Companies arranged for additional off-system line workers and support teams from Alabama, Arkansas, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Wisconsin, and Canada to assist with the restoration efforts. In total, the Companies mobilized an army of staff and crews of approximately 20,000 people, the largest in their history, to stage throughout the Carolinas to immediately deploy as soon as it was safe to begin restoration efforts. In initiating, managing, and implementing this response to Hurricane Florence, the Companies were also required to mobilize employees for "storm duty" by diverting them from their normal day-to-day responsibilities to support storm response and recovery. This reallocation of internal assets occurred at virtually every level of the Companies and resulted in hundreds of employees working on a 24/7 basis to assist in the monumental task of restoring services and systems following the storm for the period September 10, 2018 to September 23, 2018.

7. Hurricane Michael came ashore in the Florida Panhandle on October 10, 2018, mere weeks after Hurricane Florence, as a Category 4 storm with winds as high as 155 miles per hour. The storm was quick-moving and reached the Carolinas as a tropical

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storm on October 11, 2018. This fast-moving storm brought heavy winds and rain to the already saturated DEC and DEP service territories, resulting in additional flooding and widespread damage and outages. The Companies mobilized more than 10,000 personnel from both Companies, contractors, and off-system mutual assistance crews to restore the grid. To support this response effort, the Companies were required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane-impacted areas. In addition to line crews, vegetation management professionals, and damage assessors, other support personnel worked in call centers and operations centers to answer customer outage calls, assess damage, and dispatch crews. Other support personnel handled logistics, such as meals, housing, and refueling for the crews. The Companies also provided pre-storm preparation and post-impact restoration updates to customers through traditional and social media as well as text messages and emails.

8. Beginning on December 9, 2018, Winter Storm Diego entered the Companies' North Carolina and South Carolina service territories and dumped a mix of more than a foot of snow, ice, and freezing rain in many locations through December 10, 2018. Winter Storm Diego caused widespread damage and outages and was the most significant early December storm since 2002's ice storm, causing significant damage to the Companies' distribution system and impacting more than 767,700 customers. DEC and DEP were required to mobilize more than 9,000 personnel from both Companies, contractors, and off-system mutual assistance crews to restore the grid. The Companies housed thousands of these utility workers at staging areas in the operating zones and were also required to coordinate meals and other basic services, such as refueling, for these crews

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as they went about the difficult and dangerous work of restoring power to the impacted areas.

9. Hurricane Dorian reached North Carolina on September 6, 2019, as a slow-moving Category 2 hurricane with sustained winds of up to 90 miles per hour. It first clipped Cape Lookout before making landfall at Cape Hatteras and resulted in a peak outage of more than 100,000 customers throughout the Companies' service territories. In response to Dorian, the Companies arranged for additional off-system line workers and support teams from Alabama, Arkansas, the District of Columbia, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Texas, Wisconsin, and Canada to assist with the restoration efforts. To support this response effort, the Companies were required to provide housing and logistical operations support for almost 9,000 employees, off-system mutual assistance crews, and contractors in forward deployed areas directly impacted by the hurricane. Like its other hurricane response efforts, the Companies housed thousands of these utility workers at staging areas in the operating zones. The Companies were also required to coordinate meals and other basic services for these crews as they went about the difficult and dangerous work of restoring power to hurricane-impacted areas. In preparation for the potential impacts from Hurricane Dorian, the Companies also installed temporary mitigation structures, such as tiger dams and portadam systems, at seven substations.

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PRIOR EFFORTS TO DEFER AND RECOVER STORM COSTS THROUGH RATE CASES AND THE SECURITIZATION PROCESS OF SB 559

10. On December 21, 2018, DEC and DEP filed separate applications in Docket Nos. E-7, Sub 1187 and E-2, Sub 1193, respectively, requesting that the Commission approve the deferral of each Company's cost of restoring electric service after Hurricanes Florence and Michael and Winter Storm Diego.

11. On September 30, 2019, DEC filed its Application to Adjust Retail Rates, Request for An Accounting Order and to Consolidate Dockets with the Commission pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 in Docket No. E-7, Sub 1214 requesting a net base rate increase in DEC's retail revenues of approximately $445.3 million.[3] DEC's application explained that a significant portion of the rate increase was related to expenses incurred to restore service to the approximately 1.3 million customers impacted by Hurricanes Florence and Michael, and Winter Storm Diego in late 2018. DEC's application included a request to consolidate the storm deferral docket[4] with the rate case and sought to recover DEC's deferred asset balance associated with the Storms, including a return on the unrecovered balance, and with respect to the capital investments, including a deferral of depreciation expense and a return on the investment. The application sought to amortize these costs relating to the Storms over an eight-year period. In the testimony of DEC witness Stephen G. De May, North Carolina President of DEC and DEP, witness De May stated that if SB 559 (which was then pending before the General Assembly) was

[3] On June 26, 2020, the Commission issued its *Order Consolidating Dockets* in Docket Nos. E-7, Sub 1214 and E-7, Sub 1187 granting DEC's request to consolidate Docket No. E-7, Sub 1187 with its general rate case docket. Docket No. E-7, Sub 1187 pertained to DEC's Petition for Accounting Order to Defer Storm Damage Expenses, filed December 21, 2018, requesting deferral of storm recovery costs prior to the enactment of SB 559.

[4] Docket No. E-7, Sub 1187.

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passed into law, DEC would pursue securitization if it provided customer savings and would cease the recovery of the remaining storm costs in current rates, and instead begin recovering the remaining unrecovered storm costs as provided for in a securitization financing order.[5]

12. On October 30, 2019, DEP filed its Application to Adjust Retail Rates, Request for An Accounting Order and to Consolidate Dockets with the Commission pursuant to N.C. Gen. Stat. §§ 62-133 and 62-134 in Docket No. E-2, Sub 1219 requesting a base rate increase in DEP's retail revenues of approximately $585.9 million.[6] DEP's application also explained that a significant portion of this increase was related to the recovery of expenses incurred to restore full service to approximately 2.3 million North Carolina customers that were impacted by Hurricanes Florence and Michael and Winter Storm Diego in late 2018 as well as Hurricane Dorian in 2019. In its rate case application, DEP requested an accounting order from the Commission and requested deferral treatment for costs related to Hurricane Dorian restoration efforts like what was requested in Docket No. E-2, Sub 1193. The application included a request to consolidate the storm deferral docket with the rate case and sought to recover DEP's deferred asset balance associated with the Storms, including a return on the unrecovered balance, and with respect to the capital investments, including a deferral of depreciation expense and a return on the investment. Through its application, DEP sought to amortize the incremental costs of the Storms over a 15-year period. Similar to the DEC general rate case, witness De May's

[5] Direct Testimony of Stephen De May, at 10-11, Docket No. E-7, Sub 1214 (filed Sept. 30, 2019).
[6] On August 11, 2020, the Commission issued its *Order Consolidating Dockets* in Docket Nos. E-2, Sub 1219 and E-2, Sub 1193 granting DEP's request to consolidate Docket No. E-2, Sub 1193 with its general rate case docket. Docket No. E-2, Sub 1193 pertained to DEP's Petition for Accounting Order to Defer Storm Damage Expenses, filed December 21, 2018, requesting deferral of storm recovery costs prior to the enactment of SB 559.

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direct testimony stated that if SB 559 were passed into law, DEP would pursue securitization if it provided customer savings and would cease the recovery of the remaining storm costs in current rates, and instead begin recovering the remaining unrecovered storm costs as provided for in a securitization financing order.[7]

13. On November 6, 2019, SB 559 was signed into law, establishing N.C. Gen. Stat. § 62-172 to create a new financing tool to allow utilities the ability to securitize certain storm recovery costs. Securitization is a process by which the storm recovery costs, which the Companies are entitled to recover, are not financed directly by the Companies at their overall cost of capital. Instead, securitization makes use of relatively low-cost bonds, which are secured by an irrevocable right to bill and collect storm recovery charges and obtain periodic adjustments to such charges. The storm recovery charges are separate and distinct from the Companies' base rates. This irrevocable right, also referred to as "storm recovery property," is sold to a bankruptcy-remote special purpose entity that is the issuer of the bonds. Because of the nature of the storm recovery property pledged to support the storm recovery bonds, the securitization process results in the issuance of highly-rated bonds (usually AAA or equivalent rated) to raise the capital necessary to reimburse an electric utility for its previously incurred storm recovery costs and to pay the associated financing costs relating to issuing the bonds and maintaining the structure to ensure timely payment of debt service on the bonds. This approach makes it possible to reduce each Company's overall revenue requirement associated with storm recovery costs thereby reducing costs to customers. The revenue requirement is lower because securitization

[7] Direct Testimony of Stephen De May, at 10-11, Docket No. E-2, Sub 1219 (filed Oct. 30, 2019).

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results in a lower-cost method of financing storm recovery costs in comparison to traditional cost recovery and ratemaking methods.

14. On February 18, 2020, the Public Staff and other intervenors to DEC's general rate case proceeding filed testimony in Docket No. E-7, Sub 1214. Among other things, Public Staff witness Michelle M. Boswell made an adjustment to remove all capital and O&M costs associated with the Storms in the present case because DEC had previously indicated that it would seek securitization treatment of these costs if SB 559 was enacted. Witness Boswell also stated that based upon the Public Staff's review of the costs DEC included in the general rate case, the Public Staff believed the costs associated with the Storms were prudently incurred.[8]

15. On March 4, 2020, DEC filed its rebuttal testimony in its general rate case proceeding. Among other things, DEC witness De May testified that DEC looked forward to pursuing securitization at the appropriate time but believed the cost of the Storms should remain a part of DEC's request in the rate case proceeding until the Commission reached the same determination reached by DEC and the Public Staff—that the costs were prudently incurred—and the Commission subsequently approved a financing petition.

16. On March 25, 2020, DEC and the Public Staff filed a Partial Settlement Agreement in DEC's general rate case proceeding ("DEC Settlement"). In the DEC Settlement, DEC and the Public Staff agreed that DEC's reasonable and prudently incurred storm recovery costs would be removed from Commission consideration in its rate case and instead DEC would proceed with filing a financing petition no later than 120 days from the date of the Commission's order addressing the prudency of DEC's storm recovery

[8] Direct Testimony of Michelle M. Boswell on Behalf of the Public Staff, at 27-28, Docket No. E-7, Sub 1214 (filed February 18, 2020).

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costs. For purposes of settlement, DEC and the Public Staff also agreed on the assumptions DEC would use in the securitization docket to evaluate whether securitization provides quantifiable customer benefits when compared to traditional storm cost recovery.

17. On April 13, 2020, the Public Staff and the other interveners in DEP's general rate case proceeding[9] filed testimony. Among other things, Public Staff witness Shawn L. Dorgan made an adjustment to remove all capital and O&M costs associated with the Storms in the general rate case because DEP had previously indicated that it would seek securitization treatment of those costs if SB 559 was enacted. Witness Dorgan also stated that based upon the Public Staff's review of the costs DEP had included in the rate case, the Public Staff believed the costs associated with Hurricanes Florence, Michael, and Winter Storm Diego were prudently incurred.[10] The Public Staff subsequently filed supplemental testimony and exhibits on April 23, 2020. In his supplemental testimony, witness Dorgan stated that based upon the Public Staff's review, the costs associated with Hurricane Dorian were also prudently incurred.[11]

18. On May 4, 2020, DEP filed its rebuttal testimony in its general rate case proceeding. Among other things, DEP witness De May testified that DEP looked forward to pursuing securitization at the appropriate time but believed the cost of the Storms should remain a part of DEP's request in the rate case, until the Commission reached the same determination as reached by DEP and the Public Staff—that the storm costs were prudently incurred—and the Commission subsequently approved a financing petition.

[9] Docket No. E-2, Sub 1219.
[10] Direct Testimony of Shawn L. Dorgan on Behalf of the Public Staff, at 32, Docket No. E-2, Sub 1219 (filed Apr. 13, 2020).
[11] Supplemental Direct Testimony of Shawn L. Dorgan on Behalf of the Public Staff, at 9, Docket No. E-2, Sub 1219 (filed Apr. 23, 2020).

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19. On June 2, 2020, DEP filed a Stipulation of Partial Settlement with the Public Staff in its general rate case proceeding ("DEP Settlement"). In the DEP Settlement, DEP and the Public Staff agreed that DEP's reasonable and prudently incurred storm recovery costs would be removed from Commission consideration in its rate case and instead DEP would proceed with filing a financing petition no later than 120 days from the date of the Commission's order addressing the prudency of DEP's storm recovery costs. For purposes of settlement, DEP and the Public Staff also agreed on the assumptions DEP would use in this securitization docket to evaluate whether securitization provides quantifiable customer benefits when compared to traditional storm cost recovery.

20. N.C. Gen. Stat. § 62-172(b) authorizes the Companies to finance through securitization the amount of storm recovery costs found by the Commission to be recoverable. As of the filing of this Joint Petition, the Companies are still awaiting orders in their 2019 rate cases with the determination that the storm recovery costs were reasonable and prudent and cannot proceed with securitization until such orders are received.[12] Abernathy Exhibit 2, attached to witness Melissa Abernathy's testimony, provides a reconciliation of storm recovery costs as of the date of the last update in each of DEC and DEP's general rate cases to the storm recovery costs projected through May 31, 2021, to be recovered using storm recovery bonds. Once final orders are issued in the rate cases, the Companies will update their proposed storm recovery cost amounts, if needed, to ensure compliance with the Commission's final rate case orders and N.C. Gen. Stat. § 62-172(b).

[12] The Companies note, however, that there is no evidence in the rate cases challenging the prudency or amounts of storm recovery costs reported by the Companies.

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21. Accordingly, pursuant to N.C. Gen. Stat. § 62-172, the Companies seek approval of the proposed forms of Financing Orders for DEC and DEP, attached hereto as Joint Petition Exhibits B and C, respectively. By approving each of the proposed Financing Orders, the Commission: (1) authorizes DEC and DEP to securitize the storm recovery costs, updated through the projected date of issuance of the storm recovery bonds, found to be prudent and reasonable in the pending general rate proceedings and allow storm recovery bonds to be issued in an aggregate amount equal to (a) for DEC, consisting of the sum of (i) storm recovery costs for DEC (including carrying costs on such amounts through the issuance date of the storm recovery bonds, calculated at the relevant weighted average cost of capital approved by this Commission) as defined above and (ii) up-front financing costs incurred in connection with issuance of the storm recovery bonds for DEC; and (b) for DEP, consisting of the sum of (i) storm recovery costs for DEP (including carrying costs on such amounts through the issuance date of the storm recovery bonds, calculated at the relevant weighted average cost of capital approved by this Commission) as defined above and (ii) up-front financing costs incurred in connection with issuance of the storm recovery bonds for DEP; (2) approves the structure of the proposed securitization financing; (3) approves storm recovery charges for DEC and DEP in an amount, calculated and adjusted from time to time as provided in the Financing Orders, to be sufficient to pay the debt service on the storm recovery bonds together with related financing costs on a timely basis; and (4) approves DEC and DEP's proposed tariffs for each utility that apply the storm recovery charges to become effective as of the date of issuance of the storm recovery bonds.

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22. In addition, the Companies request that the Commission consider and approve the relief requested in this Joint Petition as soon as practicable following a final order in each Company's pending general rate case, and within the 135-day period from the date of filing of this Joint Petition as set forth in N.C. Gen. Stat. § 62-172(b)(3)a.2.

FINANCING AND STORM RECOVERY COSTS

23. The Companies request that their up-front financing costs associated with the securitization process be included in the principal amount of storm recovery bonds.[13] Principal, interest, and on-going financing costs, including, but not limited to costs of servicing and maintaining the storm recovery bonds, will be recovered through the storm recovery charges authorized by the Financing Orders. DEC estimates that its up-front financing costs will be $5.2 million, and that its annual on-going financing costs of the storm recovery bonds will total approximately $.44 million annually.[14] DEP estimates that its up-front financing costs will be $9 million and that its annual on-going financing costs of the storm recovery bonds will total approximately $.91 million annually.[15] These estimates are based upon each Company acting as a servicer for their respective Special Purpose Entities ("SPE), as more fully described below.

24. A list of the estimated up-front financing costs is included as an exhibit to the testimony of witness Thomas J. Heath, Jr. filed concurrently herewith. However, several of the components of the up-front financing costs will vary depending upon the size of the final issuance of the storm recovery bonds. Specifically, the U.S. Securities and

[13] N.C. Gen. Stat. § 62-172(a)(4)c.; N.C. Gen. Stat. § 62-172(a)(12)—(13).
[14] N.C. Gen. Stat. § 62-172(b)(1)e. requires a public utility petitioning the Commission for a Financing Order to estimate the total Financing Costs (as defined in Section 62-172(a)(4)) related to the storm recovery bonds, including the estimated costs of issuing the storm recovery bonds.
[15] *Id.*

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Exchange Commission ("SEC") registration fee and the underwriters' fees are typically proportional to the amount of a bond issuance. In addition, other up-front costs, such as legal, consulting and accounting fees and expenses, rating agency fees, printing expenses, and trustee costs will not be known until the issuance of the storm recovery bonds, when final invoices are submitted. Finally, any costs incurred by the Commission or the Public Staff for any outside consultants or counsel retained in connection with the securitization are up-front financing costs under the statute.[16] The Commission and Public Staff's costs will not be known until the issuance of the storm recovery bonds and final invoices are submitted prior to bond pricing. Accordingly, final up-front financing costs will not be known until after the final terms of the issuance have been established. Final up-front financing costs will be approved through the issuance advice letter procedures as proposed in the draft Financing Orders and described in the testimony of witness Charles N. Atkins II.

25. If the actual up-front financing costs are in excess of the amounts appearing in the issuance advice letter, the Companies have no ability to collect this excess amount through the storm recovery charge. Therefore, the Companies are seeking permission to establish a regulatory asset to defer any prudently incurred excess amounts of up-front financing costs, to preserve those costs for later recovery in each Company's next general rate case proceeding.

26. The Securitization Statute does not contemplate Commission involvement in the bond issuance process following granting of a financing order, which is consistent with the Commission's historic practice of allowing public utilities authority to execute

[16] N.C. Gen. Stat. § 62-172(a)(4)f.

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Commission-approved transactions without further regulatory action. In other public utility bond offerings, however, some state utility commissions have elected or have been statutorily required to participate in the bond issuance process. Therefore, to the extent requested by the Commission, the Companies propose to provide a Commissioner or Commission Staff member (a "Designated Member") with timely information to allow for the Designated Member's participation in the actual structuring, pricing, and issuance of the storm recovery bonds. The Companies' proposed Financing Orders contemplate this continued Commission involvement, as discussed further by witness Atkins.

DEC

27. As discussed in the testimony of witness Abernathy, DEC seeks recovery through securitization of approximately $230.8 million in storm recovery costs, which includes $18.6 million in capital investment, $169.8 million in O&M expense, plus $37.2 million in carrying costs assuming a June 1, 2021 issuance date,[17] and approximately $5.2 million of up-front financing costs as described above. The total amount of carrying costs is subject to the adjustment necessary to account for the number of days, as applicable either greater than or less than assumed in the carrying cost calculations. Accordingly, DEC proposes to finance its total storm recovery costs through securitization, subject to the prudency determination by the Commission undertaken in DEC's general rate

[17] N.C. Gen. Stat. § 62-172(b)(1)b. requires that a public utility petitioning the Commission for a financing order shall describe the storm recovery costs and estimates of the costs of any storm related activities that are being undertaken to be financed by issuing storm recovery bonds.

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proceeding, Docket No. E-7, Sub 1214.[18,19] The details of DEC's storm recovery activities resulting in these costs are further described in the testimony of witness Rufus S. Jackson in DEC's general rate case proceeding, Docket No. E-7, Sub 1214, and exemplify that DEC's storm recovery costs were reasonable and prudently incurred.[20,21] Note also at this time, DEC does not intend to use any of the proceeds of the issuance of storm recovery bonds to fund storm recovery reserves.[22]

28. As also exemplified in witness Abernathy's testimony and Abernathy DEC Exhibit 2, DEC's storm recovery costs, less carrying costs from July 31, 2020, to the issuance date of the storm recovery bonds, were included in DEC's general rate case proceeding, Docket No. E-7, Sub 1214, and have been subject to discovery and audit by the Public Staff and intervenors as part of that proceeding. No party to DEC's general rate case proceeding has contested the Company's storm recovery costs, and the Public Staff has specifically concluded that DEC's storm recovery costs were reasonable and prudently incurred. DEC requests recovery of such storm recovery costs through securitization.

DEP

29. As discussed in the testimony of witness Abernathy, DEP seeks recovery through securitization of approximately $748.0 million in storm recovery costs, which

[18] N.C. Gen. Stat. § 62-172(b)(1)c. requires a public utility petitioning the Commission for a financing order to indicate "the level of the storm recovery reserve that the public utility proposes to establish or replenish." At this time, DEC does not intend to use any of the process of the issuance of storm recovery bonds to fund storm recovery reserves.

[19] N.C. Gen. Stat. § 62-172(b)(1)d. requires a public utility petitioning the Commission for a financing order to indicate whether the utility proposes to finance all or a portion of the storm recovery costs using storm recovery bonds.

[20] N.C. Gen. Stat. § 62-172(b)(1)a. requires that a public utility petitioning the Commission for a financing order shall provide "a description of the storm recovery activities that the public utility has undertaken or proposes to undertake and the reasons for undertaking the activities."

[21] Direct Testimony of Rufus S. Jackson, Docket No. E-7, Sub 1214 (filed Sept. 30, 2019).

[22] N.C. Gen. Stat. § 62-172(b)(1)c. requires a public utility petitioning the Commission for a Financing Order to indicate "the level of the storm recovery reserve that the public utility proposes to establish or replenish."

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includes $68.6 million in capital investment, $556.6 million in O&M, plus $113.8 million in carrying costs assuming a June 1, 2021 issuance date,[23] and approximately $9 million of up-front financing costs as described above. The total amount of carrying costs is subject to the adjustment necessary to account for the number of days, as applicable, either greater than or less than assumed in the carrying cost calculations. Accordingly, DEP proposes to finance its total storm recovery costs through securitization subject to the prudency determination by the Commission undertaken in DEP's general rate proceeding, Docket No. E-2, Sub 1219.[24,25] The details of DEP's storm recovery activities resulting in these costs are further described in the direct testimony of witness Jackson in DEP's general rate case proceeding, Docket No. E-2, Sub 1219, and exemplify that DEP's storm recovery costs were reasonable and prudently incurred.[2627] Note also at this time, DEP does not intend to use any of the proceeds of the issuance of storm recovery bonds to fund storm recovery reserves.[28]

30. As exemplified in witness Abernathy's testimony and Abernathy DEP Exhibit 2, DEP's storm recovery costs, less carrying costs from August 31, 2020, to the issuance date of the storm recovery bonds, were included in DEP's general rate case proceeding, Docket No. E-2, Sub 1219, and have been subject to discovery and audit by

[23] *See* N.C. Gen. Stat. § 62-172(b)(1)b.
[24] N.C. Gen. Stat. § 62-172(b)(1)c. requires a public utility petitioning the Commission for a financing order to indicate "the level of the storm recovery reserve that the public utility proposes to establish or replenish." At this time, DEP does not intend to use any of the process of the issuance of storm recovery bonds to fund storm recovery reserves.
[25] N.C. Gen. Stat. § 62-172(b)(1)d. requires a public utility petitioning the Commission for a financing order to indicate whether the utility proposes to finance all or a portion of the storm recovery costs using storm recovery bonds.
[26] N.C. Gen. Stat. § 62-172(b)(1)a.
[27] Direct Testimony of Rufus S. Jackson, Docket No. E-2, Sub 1219 (filed Oct. 30, 2019).
[28] N.C. Gen. Stat. § 62-172(b)(1)c. requires a public utility petitioning the Commission for a Financing Order to indicate "the level of the storm recovery reserve that the public utility proposes to establish or replenish."

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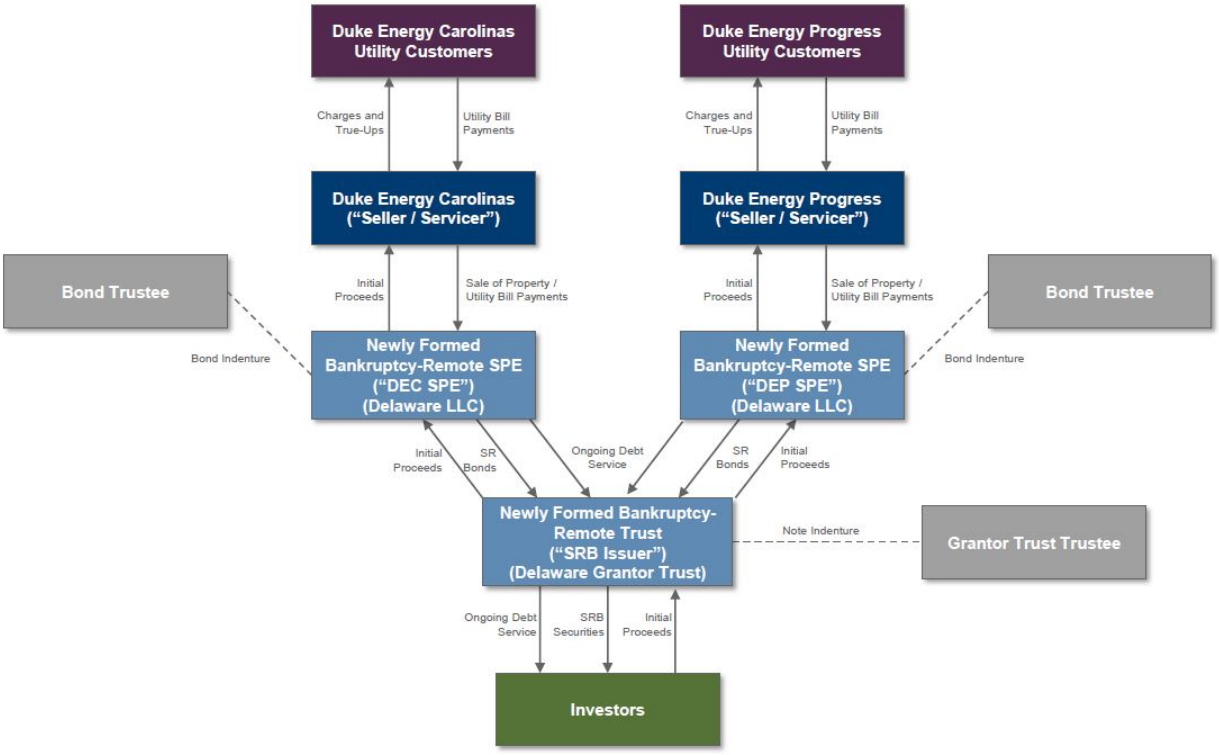
the Public Staff and interveners as part of that proceeding. No party to DEP's general rate case proceeding has contested the Company's storm recovery costs, and the Public Staff has specifically concluded that DEP's storm recovery costs were reasonable and prudently incurred. DEP requests recovery of such storm recovery costs through securitization.

STRUCTURE OF ISSUANCE



31. As further discussed in the testimony of witnesses Atkins and Heath, to facilitate the proposed securitization, DEC and DEP will each create one or more wholly-owned, bankruptcy-remote special purpose storm recovery funding entities ("SPE"),[29] which will purchase the applicable storm recovery property of each Company including the rights to impose, bill, charge, collect, and receive storm recovery charges and issue the

[29] For purposes of this Petition, all references to SPE shall be applicable to all SPEs that are created to issue any separate series of storm recovery bonds.

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applicable storm recovery bonds.[30] DEC and DEP will perform the necessary servicing and administrative functions for their respective SPE,[31] and the sole member of each SPE will be the respective utility. The proposed structure will ensure a true sale of the storm recovery property to a bankruptcy-remote issuer pursuant to N.C. Gen. Stat. § 62-172(2)(e)(3) and help ensure that securitization of the storm recovery costs provides quantifiable benefits to customers, as discussed further below.

32. The storm recovery bonds can be issued in a registered public offering or unregistered exempt offering and will be structured to achieve the highest possible credit rating from applicable rating agencies. In either case, there will be extensive marketing of the storm recovery bonds to ensure a broad solicitation of potential, unaffiliated investors, as further described in testimony of witness Atkins.

33. Upon issuance of the storm recovery bonds, each SPE will transfer the net proceeds from the sale of the storm recovery bonds to DEC and DEP as consideration for the transfer of the storm recovery property. Thus, each SPE will be a transferee, purchaser, acquirer, assignee, or pledgee of the applicable storm recovery property as provided for in N.C. Gen. Stat. §62-172(e)(1)e.

34. To maximize flexibility, the Companies are also seeking authority to issue storm recovery bonds to a special purpose trust jointly formed by the Companies or formed by Duke Energy Corp. (the "SRB Issuer"). Notes or similar instruments would be issued by the SRB Issuer and backed by each SPE's storm recovery bonds held by the SRB Issuer

[30] DEC and DEP will enter into a limited liability company agreement for each SPE. A limited liability company agreement is the key organizational and governing document for the SPE.
[31] DEC and DEP will enter into an administration agreement and servicing agreement with each SPE, which will provide for the servicing and administrative functions that DEC or DEP, as the case may be, would provide to the relevant SPE.

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("SRB Securities"). The SRB Issuer would engage in no activities other than the holding of storm recovery bonds and the issuance of SRB Securities and related activities. The SRB Securities would be sold either through a registered public offering or unregistered exempt offering, and structured to achieve the highest possible credit rating from applicable rating agencies based upon the underlying structure of the SRB Issuer-owned storm recovery bonds secured by storm recovery property and supported by the true-up mechanism. Finally, the SRB Issuer would transfer an allocable portion of net proceeds from the sale of the SRB Securities to each SPE and each such SPE would then transfer those proceeds to DEC and DEP in consideration of the storm recovery property sold to each SPE by DEC and DEP. In the proposed structure, none of the SPEs would be obligated, however, with respect to any other SPE's storm recovery bonds; therefore, the customers of the respective Companies would not be obligated to pay storm recovery charges relating to storm recovery bonds issued by the wholly-owned SPE of another Company or be responsible for the adequacy of the storm recovery property of such other Company. This transaction is described more specifically in the testimonies of witnesses Heath and Atkins.

35. Similar to a sale of the storm recovery bonds directly to unaffiliated investors, storm recovery bonds sold to the SRB Issuer will be indirectly secured by and payable solely out of the storm recovery property created pursuant to the Financing Orders issued by the Commission. Combining the issuance of the storm recovery bonds by each of the Companies in one transaction through the use of the SRB Issuer is expected to result in lower issuance costs and other efficiencies, thereby lowering costs for each Company's customers to help achieve the Statutory Cost Objectives.

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36. By allowing the Companies flexibility to determine which of these structures are best tailored to then-existing rating agency considerations, market conditions, and investor preferences, the financing of storm recovery costs can achieve the Statutory Cost Objectives.

STORM RECOVERY CHARGES AND TARIFFS

37. Pursuant to a servicing agreement between each of DEC and DEP and their respective SPE,[32] DEC and DEP will act as the initial servicer of the storm recovery charges for their respective SPE. As servicers, DEC and DEP will undertake to bill, receive, and collect such charges from their applicable retail customers, and will remit these collections to an indenture trustee for each series of storm recovery bonds on behalf, and for the account, of each of their respective SPEs. The Companies, as servicers, will be responsible for making any required or allowed true-ups of the storm recovery charges as provided for in each Financing Order.

38. The storm recovery charges collected by DEC and DEP pursuant to the servicing agreement will be calculated to ensure the collection of an amount sufficient to timely pay the principal and interest on the storm recovery bonds and the on-going financing costs. The total revenue requirement over the proposed 15-year bond period for the storm recovery charges is approximately $262 million for DEC and $842 million for DEP. The annual revenue requirement is shown in Abernathy Exhibit 4 for each Company. The storm recovery charges will be allocated to the various customer classes in the manner determined by the Commission and set forth in the Financing Orders.

[32] A servicing agreement details the services that DEC or DEP will provide, as servicer, to the relevant SPE, principally with respect to billing, collecting, and receiving of the applicable storm recovery charges.

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39. The storm recovery charges will be billed, received, and collected pursuant to DEC and DEP's respective storm recovery tariffs, included as Byrd Exhibit 2 attached to witness Jonathan Byrd's testimony.

40. Although the exact calculation of the storm recovery charges cannot be made until all the final terms of the storm recovery bonds are known, DEC estimates that the initial storm recovery charges imposed on the monthly electric bill of one of its residential customers using 1,000 kWh will be $0.57 per month.[33] DEP estimates that the initial storm recovery charges imposed on the monthly electric bill of one of its residential customers using 1,000 kWh will be $2.81 per month.[34]

41. In order to synchronize the collection of storm recovery charges with the first payment on the storm recovery bonds, the tariffs for each utility that apply the storm recovery charges will become effective as of the date of issuance of the storm recovery bonds.

42. The Companies, as servicers of the storm recovery bonds, will make, at least semi-annually (quarterly beginning 12 months prior to the scheduled final payment date of the latest maturing tranche of a series of storm recovery bonds), true-up adjustments to the storm recovery charges to correct (a) any under-collections or over-collections or (b) otherwise ensure the timely payment of storm recovery bonds and on-going financing costs and other required amounts and charges payable in connection with the storm recovery bonds pursuant to N.C. Gen. § 62-172(b)(3)b.6. In addition, each servicer will make optional interim true-up adjustments at any time in order to ensure the recovery of

[33] N.C. Gen. Stat. § 62-172(b)(1)f., requires DEC and DEP to estimate the storm recovery charges necessary to recover the storm recovery costs and financing costs and the period for recovery of such costs.
[34] *Id.*

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revenues sufficient to provide for the timely payment of the storm recovery bonds and all on-going financing costs payable in connection with the storm recovery bonds. The true-up mechanism is discussed in the testimony of witness Shana Angers.

SECURITIZATION BENEFITS

43. N.C. Gen. Stat. § 62-172(b)(1)g. requires the Companies to demonstrate that the issuance of the storm recovery bonds to recover the storm recovery costs are expected to result in quantifiable benefits to customers. To demonstrate quantifiable benefits, the Companies must provide a comparison between the net present value of the costs to customers that are estimated to result from the issuance of storm recovery bonds and the costs to customers that would result from the application of the traditional method of financing and recovering storm recovery costs.

44. In both the DEC and DEP Settlements, the Companies and the Public Staff jointly agreed to demonstrate quantifiable benefits to customers, in accordance with N.C. Gen. Stat. § 62-172(b)(1)g., by showing that the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery using a specific set of assumptions that must be followed in making such comparison.[35] Having made this comparison in accordance with N.C. Gen. Stat. § 62-172(b)(1)g. and the DEC and DEP Settlements, DEC calculates that approximately $58 million, or 32%, in customer savings are expected to be achieved

[35] As discussed in witness Abernathy's testimony, the DEC and DEP Settlements require the Companies to make the following assumptions: (1) For traditional storm cost recovery, 12 months of amortization for each Storm was expensed prior to the new rates going into effect; (2) For traditional storm cost recovery, no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance; (3) For traditional storm cost recovery, no carrying charges were accrued on the deferred balance during the 12-month period following the date(s) of the Storm(s); (4) For traditional cost recovery, the amortization period for the Storms is a minimum of 10 years; and (5) For securitization, the imposition of the storm recovery charge begins nine months after the new rates go into effect.

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through securitization of its Storm recovery costs. Similarly, DEP calculates that approximately $199 million, or 33%, in customer savings will be achieved through securitization of its storm recovery costs. These calculations are further discussed and supported by witness Abernathy in her testimony and in Abernathy Exhibits 5 – 7.

45. N.C. § 62-172(b)(3)b.2. requires the Commission to find that the proposed issuances of storm recovery bonds and the imposition and collections of storm recovery charges are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of storm recovery bonds. As explained above and shown specifically in the calculations provided in Abernathy Exhibit 5 to witness Abernathy's testimony, the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery for customers using the agreed-upon set of assumptions utilized in making such comparison.

46. In addition, N.C. Gen. Stat. § 62-172(b)(3)b.3. requires the Commission find that the proposed structuring and pricing of the storm recovery bonds are reasonably expected to result in the lowest storm recovery charges consistent with market conditions at the time the storm recovery bonds are priced and the terms of the Financing Orders. The final structure and terms of the storm recovery bonds will be determined shortly before their issuance, in accordance with the Financing Orders. As described in the testimony of witness Atkins, the Companies will work with an underwriter(s) to tailor the bond structure to the then-existing market conditions, rating agency considerations, and investor preferences, in order that the financing of storm recovery costs achieve the Statutory Cost Objectives.

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47. As described above, the Companies may jointly issue SRB Securities through the SRB Issuer. In doing so, the Companies will be able to enhance the marketability of the transactions and increase efficiencies to achieve the Statutory Cost Objectives. The Companies will also be able to engage in joint marketing, resulting in additional cost savings and the marketing of larger bonds to a broader group of investors. Combining the transactions will also allow for a larger aggregate principal amount to better position the SRB Securities to be listed on the Bloomberg Barclays Aggregate Bond index, which should increase investor demand resulting lower overall interest rates.

48. To maximize the benefits from securitization for customers, it is necessary to obtain AAA-equivalent credit ratings for the storm recovery bonds and, if applicable, the SRB Securities. Necessary elements for such credit ratings include, but are not limited to: (1) the nonbypassability of the storm recovery charges pursuant to N.C. Gen. Stat. § 62-172(b)(3)b.4; (2) a true sale of the storm recovery property to a bankruptcy-remote issuer, which will be each utility's respective SPE; (3) a mandatory periodic formula-based true-up mechanism to adjust storm recovery charges to ensure that storm recovery bond debt service and ongoing financing costs are paid on time as scheduled; (4) the requirement that the Commission will not amend, modify, or terminate the Financing Orders or otherwise adjust the storm recovery charges, except for the periodic true-ups, as required by N.C. Gen. Stat. §§ 62-172(b)(3)e. and (k); (5) the pledge to the holders of storm recovery bonds of the SPE collection accounts established for timely remittances of storm recovery charges; (6) a statutory pledge that neither the State nor the Commission may impair the rights of storm recovery bond holders; (7) provisions for successor servicers and related fees; and (8) demonstration that the proposed transaction structures are designed to

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satisfy specified rating agency stress case cash flow scenarios. These elements are discussed further in the testimony of witness Atkins.

49. The proposed transactions and the proposed form of Commission Financing Orders authorizing the transactions have been carefully structured to provide these assurances to the rating agencies and thus to permit the storm recovery bonds to achieve AAA-equivalent credit ratings, which is essential in optimizing the customer benefits of securitization.

50. In sum, financing the Companies' storm recovery costs through securitization is expected to result in a lower revenue requirement for DEC and DEP, thereby providing quantifiable benefits to the Companies' customers than would otherwise be required without securitization. More specifically, DEC and DEP's revenue requirement related to storm recovery costs will be financed and calculated utilizing a lower cost capital structure through securitization than would be the case under traditional cost recovery. Therefore, financing the Companies' storm recovery costs using the proposed securitization structure is expected to result in quantifiable benefit to customers, in comparison to the traditional method of financing and recovering storm recovery costs.

SUPPORTING ATTACHMENTS

51. The Companies have attached hereto, and made part of this Joint Petition, the following documents in accordance with N.C. Gen. Stat. § 62-172(b)(1)h.:

- Joint Petition Exhibit A: Summary of Securitizable Balances
- Joint Petition Exhibit B: DEC Proposed Financing Order
- Joint Petition Exhibit C: DEP Proposed Financing Order

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- Joint Petition Exhibit D: Proposed Registration, Rating Agency, and Bond Issuance Timeline
- Direct Testimony and Exhibits of Thomas J. Heath, Jr.
- Direct Testimony and Exhibits of Charles N. Atkins II
- Direct Testimony and Exhibits of Melissa Abernathy
- Direct Testimony and Exhibits of Jonathan Byrd
- Direct Testimony and Exhibits of Shana W. Angers

Additionally, the Companies request that the Commission incorporate by reference the DEC and DEP Settlements, direct testimony and exhibits of Rufus S. Jackson filed in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219; the direct, rebuttal, and settlement supporting testimony of Stephen G. De May filed in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219; the direct testimony and exhibits of Michelle M. Boswell on behalf of the Public Staff, filed in Docket No. E-7, Sub 1214 on February 18, 2020; and the supplemental direct testimony of Shawn L. Dorgan filed on behalf of the Public Staff, filed in Docket No. E-2, Sub 1219 on April 23, 2020, as well as take Administrative Notice of the Commission's final Orders in Docket Nos. E-2, Sub 1214 and E-7, Sub 1219.

CONCLUSION

WHEREFORE, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission: (1) grant authorization for the financing of the Companies' storm recovery costs found to have been reasonable and prudently incurred as a result of the Storms using a securitization structure permitted by SB 559 in DEC's general rate case proceeding, Docket No. E-7, Sub 1214 and DEP's general rate case proceeding, Docket No. E-2, Sub 1219; (2) find that the Companies' storm recovery costs and up-front

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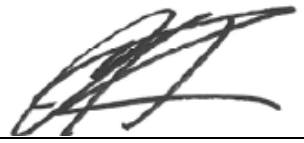
financing costs are appropriately financed by debt secured by storm recovery property; (3) issue Financing Orders for DEC and DEP by which each utility may accomplish such securitization transaction, so that the Companies may recover their prudently incurred storm recovery costs; (4) approve the storm recovery charges for DEC and DEP; (5) approve the tariffs of DEC and DEP to apply the respective storm recovery charges; (6) establish a regulatory asset to defer any prudently incurred excess amounts of up-front financing costs to preserve for later recovery in their next respective general rate case proceeding; and (7) provide any further relief the Commission deems to be just and reasonable and in the public interest.

Respectfully submitted this 26th day of October, 2020.



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Joint Petition Exhibit A:
Summary of Securitizable Balance

Docket No. E-7, Sub 1243
Docket No. E-2, Sub 1262

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SUMMARY OF CALCULATION OF DUKE ENERY CAROLINAS, LLC'S SECURITIZABLE BALANCE

Estimated Storm Recovery Costs (incremental O&M costs and capital investments)	$ 188,374,000
Estimated Carrying Costs through bond issuance date[1]	$ 37,196,000
Estimated Up-front Financing Costs[2]	$ 5,230,000
Estimated Principal Amount of Storm Recovery Bonds	$ 230,800,000

SUMMARY OF CALCULATION OF DUKE ENERGY PROGRESS, LLC'S SECURITIZABLE BALANCE

Estimated Storm Recovery Costs (incremental O&M costs and capital investments)	$ 625,193,000
Estimated Carrying Costs through bond issuance date[1]	$ 113,815,000
Estimated Up-front Financing Costs[2]	$ 8,992,000
Estimated Principal Amount of Storm Recovery Bonds	$ 748,000,000

[1] Assuming the Storm Recovery Bonds are issued on approximately June 1, 2021.
[2] Final Up-front Financing Costs to be included in the Issuance Advice Letter.

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Joint Petition Exhibit B:
DEC Proposed Financing Order

Docket No. E-7, Sub 1243
Docket No. E-2, Sub 1262

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1243

In the Matter of Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC For Issuance of a Storm Cost Recovery Docket Financing Order	**PROPOSED FINANCING ORDER OF DUKE ENERGY CAROLINAS, LLC**

BEFORE: Chair Charlotte A. Mitchell, Presiding; Commissioners ToNola D. Brown-Bland; Lyons Gray; Daniel G. Clodfelter; Kimberly W. Duffley; Jeffrey A. Hughes; and Floyd B. McKissick, Jr.

APPEARANCES:

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BY THE COMMISSION: This Financing Order addresses the petition of Duke Energy Carolinas, LLC ("DEC," "Petitioner" or the "Company") under North Carolina General Statute ("N.C. Gen. Stat.") § 62-172, filed jointly with Duke Energy Progress, LLC ("DEP," and together with DEC, the "Companies") ("Joint Petition"): (1) to finance its Securitizable Balance;[1] (2) for approval of the proposed securitization financing structure; (3) for approval to issue Storm Recovery Bonds,[2] secured by the pledge of Storm Recovery Property, in one or more series in an aggregate principal amount not to exceed the relevant Securitizable Balance (as of the date the first series Storm Recovery Bonds are issued); (4) for approval of the Financing Costs, including up-front Financing Costs ("Up-front Financing Costs"),[3] incurred in connection with the issuance of Storm Recovery Bonds and on-going Financing Costs ("On-going Financing Costs" and together with Up-front Financing Costs, "Financing Costs");[4] (5) for approval to create Storm Recovery

[1] *See* page 8 defining "Securitizable Balance."
[2] All capitalized terms not otherwise defined herein shall have the meaning assigned to them in N.C. Gen. § Stat. 62-172 and refer specifically to DEC's particular transaction approved herein.
[3] Up-front Financing Costs are defined in the Evidence and Conclusions for Finding of Fact No. 6.
[4] On-going Financing Costs are defined in the Evidence and Conclusions for Finding of Fact No. 23 & 24.

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Property, including the right to (i) impose, bill, charge, collect and receive nonbypassable Storm Recovery Charges sufficient to recover the principal of, and interest on, the Storm Recovery Bonds plus On-going Financing Costs and (ii) obtain periodic formulaic adjustments to the Storm Recovery Charge as provided in this Financing Order; and (6) for approval of the tariff to implement the Storm Recovery Charge ("Tariff").

PROCEDURAL HISTORY

In 2018, DEC incurred significant storm expenditures from Hurricanes Florence and Michael and Winter Storm Diego (collectively, the "Storms").

Subsequently, on December 21, 2018, the Company filed a Petition for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego, in Docket No. E-7, Sub 1187 ("Storm Deferral Docket").

On September 30, 2019, DEC filed an application ("Application") with the Commission in Docket No. E-7, Sub 1214 ("2019 DEC Rate Case") requesting a general rate increase, pursuant to N.C. Gen. Stat. §§ 62-133 and -134 and Commission Rule R1-17, along with direct testimony and exhibits. The Application included a request to consolidate the Storm Deferral Docket with the rate case and sought to recover DEC's deferred asset balance associated with the Storms, including a return on the unrecovered balance, and with respect to the capital investments, including a deferral of depreciation expense and a return on the investment ("Storm Recovery Costs").

On November 6, 2019, SB 559 was signed into law, amending N.C. Gen. Stat. § 62-172 to create a new financing tool that may be used by a utility to recover storm restoration costs, utility cost recovery charge securitization (or the "Securitization

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Statute"). Under this financing tool, an electric public utility company can issue storm recovery bonds with lower financing costs that are secured by storm recovery property including a dedicated storm recovery charge that is separate and distinct from the utility's base rate.

After conducting substantial discovery on the issues raised in the Application, the Public Staff – North Carolina Utilities Commission ("Public Staff") determined that Storm Recovery Costs were prudently incurred.[5]

On March 25, 2020, in Docket No. E-7, Sub 1214, DEC and the Public Staff reached an Agreement and Stipulation of Partial Settlement ("DEC Settlement") with respect to several revenue requirement issues presented by the Company's Application, including the ratemaking treatment of the deferred expenses associated with the Storms. Pursuant to the DEC Settlement, the Company agreed to remove certain capital and operation and maintenance ("O&M") costs ("Storm Expenses") associated with the Storms from its revenue requirement in the 2019 DEC Rate Case and instead file a petition for a financing order under the Securitization Statute. For purposes of settlement, DEC and the Public Staff also agreed on the assumptions to be used in the securitization docket to evaluate whether securitization provides quantifiable customer benefits when compared to traditional storm cost recovery as required by Section (b)(1)(g) of the Securitization Statute.

On October 16, 2020, pursuant to the Securitization Statute, DEC, along with DEP, filed its Joint Petition for issuance of a storm recovery financing order to recover their respective Storm Expenses.

[5] Testimony of Michelle M. Boswell Public Staff—North Carolina Utilities Commission, at 27-28, Docket No. E-7, Sub 1214 (filed Feb. 28, 2020).

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The Commission approved the DEC Settlement in Docket No. E-7, Sub 1214 on ____ ("DEC Rate Order"), removing from Commission consideration in that docket the Company's initial request for recovery of its Storm Expenses, and recognizing the Company's authority to instead file a petition for financing order under the Securitization Statute to securitize its Storm Expenses. Additionally, by the Commission's DEC Rate Order, the Commission determined that the Storm Recovery Costs (as defined therein) were reasonable and prudently incurred.

STATUTORY FRAMEWORK

The Securitization Statute establishes the process by which a public utility may petition the Commission for a financing order authorizing the public utility to finance storm recovery costs associated with storm recovery activities with the proceeds of storm recovery bonds that are secured by the storm recovery property. Before granting a financing order, the Commission must find that the issuance of the storm recovery bonds and the imposition of storm recovery charges are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of storm recovery bonds. *See* N.C. Gen. Stat. § 62-172(b)(3)b.2.

To support this finding, the utility must submit a petition that includes (a) a description of its storm recovery activities; (b) an estimate of the storm recovery costs; (c) the proposed level of storm recovery reserve, if any; (d) an indicator of the amount of storm recovery costs to be financed using storm recovery bonds; (e) an estimate of the financing costs related to the storm recovery bonds; (f) an estimate of the storm recovery charges necessary to recover storm recovery costs; and (g) a comparison between the net present value of the cost to customers estimated to result from the issuance of storm recovery bonds

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and the cost that would result from the application of the traditional method of financing and recovering storm recovery costs; this comparison must demonstrate that the issuance of storm recovery bonds and the imposition of storm recovery charges are expected to provide quantifiable benefits to customers. *See* N.C. Gen. Stat. § 62-172 (b)(1)a.-g.

When issued, the financing order must include the amount of storm recovery costs to be financed using storm recovery bonds, the imposition and collection of storm recovery charges that are nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service from the public utility or its successors or assignees, the maturity period of the bonds, a formula-based true-up mechanism, the creation of storm recovery property that will be used to secure the bonds, and a method of tracing funds collected as storm recovery charges. *See* N.C. Gen. Stat. § 62-172(b)(3)b.1.-12.

The Securitization Statute specifies that the financing order must also include a requirement that the public utility file with the Commission at least annually a letter applying the formula-based mechanism, and request adjustments in the storm recovery charge, if necessary, to a sufficient level to ensure the bond payment obligations. The Commission does not have the discretion to disapprove or alter the true-up calculation, except to correct mathematical and clerical errors.

Based on the entire record in this proceeding, the Commission now makes the following:

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FINDINGS OF FACT

Jurisdiction

1. DEC is (1) a limited liability company duly organized and existing under the laws of the State of North Carolina; (2) duly authorized by its Articles of Organization to engage in the business of generating, transmitting, distributing and selling electric power and energy; (3) a public utility under the laws of North Carolina, and its operations in this State are subject to the jurisdiction of this Commission; (4) an investor-owned public utility; (5) a public utility under the laws of the State of South Carolina, and its operations in South Carolina are subject to the jurisdiction of the Public Service Commission of South Carolina; and (6) a public utility under the Federal Power Act, and certain of its operations are subject to the jurisdiction of the Federal Energy Regulatory Commission. DECs' service area covers 24,000 square miles in the central and western portions of North Carolina and western South Carolina. The service area includes 62 counties, 44 in North Carolina and 18 in South Carolina. The Company supplies retail electric service to approximately 2 million customers in North Carolina.

2. The Commission has jurisdiction over the rates and charges, rate schedules, classifications, and practices of DEC regarding its North Carolina operations under Chapter 62 of the General Statutes of North Carolina.

3. DEC is lawfully before the Commission based upon its petition for a financing order pursuant to N.C. Gen. Stat. §§ 62-133, and 62-172 and Commission Rule R1-17.

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JOINT PETITION

4. On October 26, 2020, DEC and DEP filed its Joint Petition for a financing order pursuant to the Securitization Statute including DEC's request to issue Storm Recovery Bonds in the amount of approximately: $230.8 million, which consists of $225.6 million of Storm Recovery Costs (including carrying costs from the date of the Storms through the projected issuance date of the Storm Recovery Bonds, calculated at the Company's approved weighted average cost of capital ("Carrying Costs")[6]), plus Up-front Financing Costs of issuing the Storm Recovery Bonds of approximately $5.2 million, which are subject to change and update prior to the pricing of the Storm Recovery Bonds plus or minus any adjustment to Carrying Costs necessary to account for the number of days, as applicable, either greater than or less than assumed in the Carrying Cost calculation based on the projected issuance date for the Storm Recovery Bonds. This amount is referred to herein as the "Securitizable Balance." The Joint Petition includes direct testimony and exhibits supporting the request, as well as a comparison between the net present value of the costs to customers that are estimated to result from the issuance of Storm Recovery Bonds and the costs that would result from the application of the traditional method of recovery of Storm Recovery Costs from customers, in accordance with the Securitization Statute.

COSTS ELIGIBLE FOR FINANCING

Storm Recovery Costs

5. Consistent with the Commission's findings and conclusions in its 2019 DEC Rate Case Order issued in Docket No. E-7, Sub 1214, Storm Recovery Costs subject

[6] This amount assumes the Storm Recovery Bonds are issued on June 1, 2021.

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to adjustments including the final amount of carrying costs through the issuance date of the Storm Recovery Bonds, are eligible for recovery through securitization and have been found to be reasonable and prudent. Furthermore, the Commission finds that (i) the proposed issuance of Storm Recovery Bonds and the imposition of Storm Recovery Charges will provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds and (ii) the structuring and pricing of the Storm Recovery Bonds are reasonably expected to result in the lowest Storm Recovery Charges consistent with market conditions at the time the Storm Recovery Bonds are priced and the terms set forth in this Financing Order (collectively, the "Statutory Cost Objectives").

Up-front Financing Costs

6. DEC's proposed Up-front Financing Costs, in the estimated amount of $5.2 million, are reasonable and prudent and eligible for recovery through securitization.

7. DEC's request to establish a regulatory asset to defer any prudently incurred Up-front Financing Costs in excess of the amounts appearing in the issuance advice letter is approved.

STRUCTURE OF ISSUANCE

8. DEC's proposed financing structure adheres to the requirements of the Securitization Statute.

Special Purpose Entities

9. For purposes of securitization it is reasonable for DEC to create one or more Special Purpose Entities ("SPEs"),[7] each of which will be a Delaware limited liability

[7] For purposes of this Financing Order, all references to the SPE shall be applicable to all SPEs that are created to issue other series of Storm Recovery Bonds pursuant to this Financing Order.

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company ("LLC") with DEC as its sole member. Any such SPE will be an "assignee" as defined in N.C. Gen. Stat. § 62-172(a)(2), when an interest in Storm Recovery Property is transferred, other than as security, to such SPE, and such SPE may issue Storm Recovery Bonds in accordance with this Financing Order.

Storm Recovery Property

10. It is reasonable for DEC to sell or otherwise transfer Storm Recovery Property to the SPE pursuant to the terms of this Financing Order. Upon the transfer by DEC of the Storm Recovery Property to the SPE, that SPE will have all of the rights, title and interest of DEC with respect to such Storm Recovery Property, including the right to impose, bill, charge, collect, and receive the Storm Recovery Charge authorized by this Financing Order and to obtain periodic formulaic adjustments to each Storm Recovery Charge. Such Storm Recovery Property is expected to be pledged by the SPE to and held and administered by an indenture trustee as collateral for payment of the Storm Recovery Bonds to ensure the Statutory Cost Objectives are achieved.

11. The State of North Carolina and its agencies, including this Commission, has pledged to and agrees with bondholders, the owners of the Storm Recovery Property, and other financing parties that the State and its agencies, including this Commission, will not alter the provisions of the Securitization Statute, which authorize the Commission to create Storm Recovery Property or take or permit any action that impairs the value of the Storm Recovery Property, as further described in N.C. Gen. Stat. § 62-172(k)(1).

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Form of Transaction Documents

12. The form Purchase and Sale Agreement,[8] Administration Agreement,[9] Limited Liability Company Agreement ("LLC Agreement"),[10] form of Indenture,[11] and Servicing Agreement,[12] filed as exhibits to witness Thomas J. Heath Jr.'s testimony, ("Transaction Documents") are in the public interest and necessary to facilitate the transaction.

Offering and Sale of Bonds

13. DEC is hereby authorized to issue the Storm Recovery Bonds through a negotiated sale or other sales option to achieve the Statutory Cost Objectives.

14. In the alternative, DEC is authorized to sell the Storm Recovery Bonds in combination with DEP to a grantor trust (the "SRB Issuer") that will issue secured pass-through notes that are backed by the Storm Recovery Bonds and storm recovery bonds issued by DEP in one transaction through the use of the SRB Issuer.

Amortization, Interest Rates, and Credit Ratings of Storm Recovery Bonds

15. The expected term of the scheduled final payment date of the last maturing tranche of bonds issued pursuant to the authority granted herein, as determined in the reasonable discretion of DEC, should be no more than 15 years from the issuance of the series of Storm Recovery Bonds. The legal maturity date of each tranche may be longer than the scheduled final payment date for that tranche.

[8] *See* Heath Exhibit 2a.
[9] *See* Heath Exhibit 2d.
[10] *See* Heath Exhibit 2e.
[11] *See* Heath Exhibit 2c.
[12] *See* Heath Exhibit 2b.

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16. We find that each tranche of the Storm Recovery Bonds should have a fixed interest rate, determined consistent with current market conditions. If market conditions change, and it becomes necessary to achieve the Statutory Cost Objectives for the one or more tranches of bonds to be issued in floating-rate mode, DEC is authorized to issue such bonds but will be required to execute agreements to swap the floating payments to fixed-rate payments.

17. DEC should strive to achieve AAA credit ratings, and DEC is authorized to provide the necessary credit enhancements, with recovery of related costs as On-going Financing Costs, to achieve such ratings.

Security for the Storm Recovery Bonds

18. DEC's utilization of a Collection Account, including a General Subaccount, a Capital Subaccount, and an Excess Funds Subaccount, is reasonable and appropriate. DEC may include other subaccounts in the Collection Account, if necessary, to obtain AAA ratings on a series of Storm Recovery Bonds.

DEC as Initial Servicers of the Storm Recovery Bonds

19. DEC's proposal to act as initial servicer of the Storm Recovery Bonds is reasonable and appropriate.

20. The on-going servicing fee for DEC, acting as the initial servicer, in the amount of 0.05 percent of the initial principal amount of the Storm Recovery Bonds plus out-of-pocket expenses provided for in the Servicing Agreement is necessary to compensate the servicer adequately and ensure the high credit quality of the Storm Recovery Bonds.

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DEC as Administrator of the SPE

21. DEC's proposal to act as an administrator of the SPE under the proposed financing transaction is reasonable and appropriate.

22. The on-going fee to be paid to the administrator of $50,000 per year plus out-of-pocket expenses included in the Administration Agreement is necessary to cover the costs and expenses of administering the SPE and to preserve the integrity of the bankruptcy-remote structure of the SPE and the high credit quality of the Storm Recovery Bonds.

On-going Financing Costs

23. The On-going Financing Costs identified in DEC's Joint Petition and that are identified in Attachment 4 of the form Issuance Advice Letter ("IAL") qualify as "financing costs" eligible for recovery pursuant to N.C. Gen. Stat. § 62-172(a)(4).

24. It is appropriate for DEC to credit back to customers all periodic servicing and administration fees in excess of DEC's or an affiliate of DEC's incremental cost of performing the servicer or administrator function in the next rate case when costs and revenues associated with the servicing and administration fees will be included in the cost of service.

Storm Recovery Bonds to be Treated as "Debt" for Federal Income Tax Purposes

25. DEC shall structure the Storm Recovery Bond transactions in a way that meets all requirements for the Internal Revenue Service's ("IRS") safe harbor treatment.

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STORM RECOVERY CHARGES

Imposition and Computation of Storm Recovery Charges

26. To repay the Storm Recovery Bonds and On-going Financing Costs, DEC is authorized to impose Storm Recovery Charges to be collected on a per-kWh basis from all applicable customer rate classes until the Storm Recovery Bonds and related Financing Costs are paid in full.

27. The Securitizable Balance to be financed using Storm Recovery Bonds shall be determined in accordance with the calculation shown in Appendix A to this Financing Order.

28. The proposed allocation methodology of the Storm Recovery Charges is based upon DEC's existing (and previously approved)[13] allocation methodology in the proposed Tariff and should be approved.

29. The State of North Carolina and its agencies, including this Commission, has pledged to and agrees with bondholders, the owners of the Storm Recovery Property, and other financing parties that the State and its agencies, including this Commission, will not, except for changes made pursuant to the True-Up Mechanism (as defined in Finding of Fact No. 32), reduce, alter, or impair the Storm Recovery Charges until any and all principal, interest, premium, Financing Costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the Storm Recovery Bonds have been paid and performed in full, as further described in N.C. Gen. Stat. § 62-172(k)(1)d.

[13] *See* 2019 Rate Order at ___.

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Treatment of Storm Recovery Charge in Tariff and on Retail Customer Bills

30. DEC's proposed Tariff complies with N.C. Gen. Stat. § 62-172(d)(1) and is appropriate for use in this proceeding.

31. DEC is authorized and directed to include the Storm Recovery Charge on each customer's bill as a separate line item and include both the rate and the amount of the charge on each bill as required by N.C. Gen. Stat. § 62-172(d)(2) and a statement that the SPE is the owner of the rights to the Storm Recovery Charges and that DEC is acting as a servicer for the SPE as required by N.C. Gen. Stat. § 62-172(d)(1).

True-Up of Storm Recovery Charges

32. The formulaic true-up mechanism ("True-Up Mechanism") and associated procedures described in DEC's Tariff are reasonable and appropriate and are hereby approved.

ISSUANCE ADVICE LETTER PROCESS

33. Because the actual structure and pricing of the Storm Recovery Bonds are unknown as of the issuance of this Financing Order, following determination of the final terms of the Storm Recovery Bonds and before issuance of the Storm Recovery Bonds, DEC will file with the Commission for each series of Storm Recovery Bonds, an IAL, as well as a form of True-Up Adjustment Letter[14] ("TUAL," and together with the IAL, the "IAL/TUAL") in the forms attached hereto as Appendices B and C. The initial Storm Recovery Charges and the final terms of the Storm Recovery Bonds described in the IAL/TUAL will be final unless before noon on the third business day after pricing the Commission issues an order finding that the proposed issuance does not comply with the

[14] The True-Up Adjustment Letter is defined in the Evidence and Conclusions for Finding of Fact No. 33.

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Standards of this Financing Order in this Finding of Fact No. 33. The "Standards of this Financing Order" are: 1) the issuance of Storm Recovery Bonds and imposition and collection of Storm Recovery Charges as authorized in this Financing Order provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds; 2) the aggregate principal amount of Storm Recovery Bonds issued does not exceed the Securitizable Balance; 3) the SRB Securities (as defined in Evidence and Conclusions for Finding of Fact Nos. 13 and 14) and Storm Recovery Bonds will be issued in one or more series comprised of one or more tranches having scheduled final payment date of no longer than 15 years; 4) the SRB Securities have received a rating of Aaa(sf) / AAA(sf) from at least two of the three major rating agencies; 5) the SRB Securities and Storm Recovery Bonds are structured to achieve substantially level debt service payments on an annual basis; 6) the issuance of the SRB Securities and Storm Recovery Bonds has been structured in accordance with IRS Rev. Proc. 2005-62; and 7) the structuring and pricing of the Storm Recovery Bonds, including the issuance of SRB Securities, resulted in the lowest Storm Recovery Charges consistent with market conditions at the time the Storm Recovery Bonds are priced and the terms set forth in this Financing Order.

MITIGATION OF RATE IMPACTS

34. The issuance of Storm Recovery Bonds and imposition and collection of Storm Recovery Charges as authorized in this Financing Order are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds. The calculation of quantifiable benefits to

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customers was prepared by the Company in accordance with the requirements set forth in the DEC Settlement.

FLEXIBILITY

35. It is appropriate to allow DEC flexibility in establishing the final terms and conditions of the Storm Recovery Bonds and therefore the ability, at its option, to cause one or more series of storm recovery bonds to be issued, in order to achieve the Statutory Cost Objectives.

CONCLUSION

36. This Financing Order adheres to the statutory requirements outlined by the Securitization Statute necessary to issue a financing order authorizing a public utility to finance storm recovery costs.

DISCUSSION AND CONCLUSIONS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1-3

Jurisdiction

The evidence supporting these findings of fact and conclusions is contained in the verified Joint Petition of DEC, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature, and are not contested by any party.

JOINT PETITION

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The Joint Petition included a description of DEC's storm recovery activities, an estimate of the Storm Recovery Costs, the proposed level of storm recovery reserve, an indicator of the amount of Storm Recovery Costs to be financed using Storm Recovery

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Bonds, an estimate of the Financing Costs related to the bonds, an estimate of the Storm Recovery Charges necessary to recover costs, and a comparison between the net present value of the cost to customers estimated to result from the issuance of Storm Recovery Bonds and the cost that would result from the application of the traditional method of financing and recovering its Storm Recovery Costs. As illustrated in the testimony of witness Melissa Abernathy, DEC's comparison demonstrated that issuance of Storm Recovery Bonds and the imposition of Storm Recovery Charges is expected to provide quantifiable benefits to customers.

The Commission finds and concludes that the Joint Petition satisfies the requirements of the Securitization Statute, as discussed further herein, by including each of the necessary items required by subsection (b)(1). Therefore, pursuant to the Securitization Statute, the Commission has jurisdiction to consider DEC's Joint Petition and the information necessary to issue a financing order as well as any other relief necessary for DEC to finance its Storm Recovery Costs.

COSTS ELIGIBLE FOR RECOVERY

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 5—7

Storm Recovery Costs

In its Joint Petition, DEC requested the authority to finance its Storm Recovery Costs through securitization of approximately $230.8 million in Storm Recovery Costs, which includes $18.6 million in capital investment, $169.8 million in O&M expense, plus Carrying Costs in the amount of $37.2 million (plus or minus any adjustment to such carrying costs necessary to account of the number of days, as applicable, either greater than or less than assumed in the carrying costs calculation), plus an estimated $5.2 million in

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Up-front Financing Costs. The amount of Carrying Costs DEC requests is calculated at the Company's approved weighted average cost of capital. The requested amount is also premised on a Storm Recovery Bond issuance date of June 1, 2021. DEC states that it will report to the Commission the final Carrying Cost so financed in the IAL as described below. N.C. Gen. Stat. § 62-172(a)(14) requires that DEC's Storm Recovery Costs eligible for financing be reasonable and prudent. Except for the Carrying Costs to be calculated as described herein, the Storm Recovery Costs were included in the Company's rate case application in Docket No. E-7, Sub 1214 and have been the subject of discovery and audit by the Public Staff and other interested parties to that proceeding. The Commission's DEC Rate Order found and concluded that DEC's Storm Recovery Costs were reasonable and prudent. Consistent with that Order, the Commission finds that DEC's Storm Recovery Costs are reasonable and prudent and therefore eligible for recovery through financing. In addition, the Commission finds that DEC's Carrying Costs associated with the Storm Recovery Costs are also reasonable and prudent. Accordingly, the Commission finds that DEC should be permitted to finance its Storm Recovery Costs including Carrying Costs as provided in this Financing Order.

Up-front Financing Costs

DEC has also requested authority to finance certain financing costs associated with the issuance of the Storm Recovery Bonds. DEC's proposed Up-front Financing Costs include but are not limited to, legal fees, consulting fees, structuring adviser fees, placement and underwriting fees, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs and any other costs necessary to issue the Storm Recovery Bonds (a

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complete list of all Up-front Financing Costs will be included on Attachment 2 of the IAL, a form of such letter with preliminary estimates of Up-front Financing Costs, is included in Appendix C of this Financing Order).

In addition, the costs of any outside consultant and counsel retained by the Commission to assist the Commission in performing its responsibilities under N.C. Gen. Stat. § 62-172(b)(3)b., and the costs incurred by the Public Staff for any outside consultants or counsel retained in connection with this securitization of the Storm Recovery Costs are Up-front Financing Costs. DEC's Up-front Financing Costs include reimbursement to DEC for amounts advanced for payment of such costs, and may also include other types of credit enhancement, not specifically described herein, including letters of credit, reserve accounts, surety bonds, interest rate swaps, interest rate locks, and other mechanisms designed to promote the credit quality and marketability of the Storm Recovery Bonds or designed to achieve the Statutory Cost Objectives. The Up-front Financing Costs of any credit enhancements shall be included in the amount of costs to be financed by the sale of Storm Recovery Bonds. DEC has provided an estimate of Up-front Financing Costs of $5.2 million based on a range of estimates in Heath Exhibit 1 attached to witness Heath's testimony.

The Commission is mindful of the fact that many of these Up-front Financing Costs, such as legal fees, will not be known until after the financing is completed. Further, other Up-front Financing Costs will vary depending on the size of the final issuance of the Storm Recovery Bonds. Specifically, the Commission realizes that the Securities and Exchange Commission ("SEC") registration fee, underwriters' fees, and rating agency fee are proportional to the amount of qualified costs actually financed. Other Up-front

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Financing Costs, such as original issue discount, will be determined at the time of the sale. We also acknowledge that the (i) costs of any outside consultant to this Commission and any outside counsel to this Commission or its Designated Member (as defined herein) to assist us in performing our responsibilities under the Securitization Statute, including services provided in assisting us in our active role for the structuring and pricing of the Storm Recovery Bonds, are costs that are solely within the control of this Commission and (ii) costs of any outside consultant or counsel retained by Public Staff are costs which are solely within the control of Public Staff and that all such costs in (i) and (ii) above are fully recoverable from Storm Recovery Bond proceeds to the extent such costs are eligible for compensation and approved for payment under the terms of such party's contractual arrangements with the Commission or Public Staff, as the case may be, as such arrangements may be modified by any amendment entered into at the Commission's or Public Staff's sole discretion. Accordingly, actual Up-front Financing Costs will not be known until after the pricing of the Storm Recovery Bonds.

N.C. Gen. Stat. § 62-172(a)(4) defines "financing costs." The Commission finds that DEC's proposed Up-front Financing Costs fall squarely within this definition, and that these issuance costs are therefore financing costs eligible for recovery pursuant to the Securitization Statute. Due to the unknown aspect of these costs, the Commission orders that to the extent the actual Up-front Financing Costs are less than the amount appearing in the final IAL filed within one business day after actual pricing of the Storm Recovery Bonds, such unspent amount will be reflected in the next True-Up Adjustment Letter (as defined herein). Conversely, to the extent that the actual Up-front Financing Costs are in excess of the amount appearing in the final IAL filed within one business day after actual

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pricing of the Storm Recovery Bonds, that DEC shall book such prudently incurred excess amounts to a regulatory asset to be recovered in the Company's next rate case.

STRUCTURE OF ISSUANCE

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

General Structure of Issuance

A description of DEC's proposed transaction is contained in its Joint Petition and the filing package submitted therewith. A brief summary of the proposed transaction is provided in this section.

DEC has proposed a transaction structure that includes all of the following:

- The use of (depending on whether more than one series of Storm Recovery Bonds are issued) one or more SPEs as issuer(s) of Storm Recovery Bonds, limiting the risks to bondholders of any adverse impact resulting from a bankruptcy proceeding of DEC or any affiliate.
- The right to impose, bill, charge, collect and receive Storm Recovery Charges that are nonbypassable and which must be trued-up at least semi-annually, but may be trued-up more frequently at the option of the servicer, to ensure the timely payment of the debt service and On-going Financing Costs as scheduled.
- The use of a collection account which includes, without limitation, a Capital Subaccount at the SPE funded initially by a deposit from DEC equal to at least 0.5 percent of the initial principal amount of the Storm Recovery Bonds issued by the SPE.
- A servicer (initially DEC) responsible for billing and collecting the Storm Recovery Charge from existing and future retail customers.
- The Federal income tax consequences of the transaction are consistent with satisfaction of the provisions established in IRS Revenue Procedure 2005-62.

More specifically, and to facilitate the proposed securitization, DEC proposed that the SPE will be created and then DEC will transfer the rights to impose, bill, charge, collect, and receive Storm Recovery Charges and to obtain true-up adjustments along with the other rights arising pursuant to this Financing Order. Upon such transfer and

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simultaneously with the issuance of Storm Recovery Bonds, these rights will become Storm Recovery Property as provided by the Securitization Statute.

DEC proposed that the SPE will issue Storm Recovery Bonds and will transfer the net proceeds from the sale of such bonds to DEC in consideration for the transfer of the Storm Recovery Property. The SPE will be organized and managed in a manner designed to achieve the objective of maintaining the SPE as a bankruptcy-remote entity that would not be affected by the bankruptcy of DEC or any other affiliate of DEC or any of their respective successors. The Company has submitted several form agreements for approval, discussed further herein, facilitating DEC's utilization of an SPE.

Specifically, DEC has proposed that the Storm Recovery Bonds be issued pursuant to an Indenture and administered by an indenture trustee. The Storm Recovery Bonds will be secured by and payable solely from the Storm Recovery Property created pursuant to this Financing Order. The Storm Recovery Property and other collateral will be pledged to the indenture trustee for the benefit of the holders of the Storm Recovery Bonds and to secure payment of principal, interest on the Storm Recovery Bonds and On-going Financing Costs.

DEC proposed that the servicer of the Storm Recovery Bonds collect the Storm Recovery Charges and remit those amounts to the indenture trustee on behalf of the SPE. The servicer will be responsible for making any required or allowed true-ups of the Storm Recovery Charges. If the servicer defaults on its obligations under the Servicing Agreement, the indenture trustee may, acting for the benefit of holders of Storm Recovery Bonds, appoint a successor servicer. DEC also proposed to act as the initial servicer for the Storm Recovery Bonds.

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Under DEC's proposal, the Storm Recovery Charges will be calculated to ensure the collection of an amount sufficient to pay the debt service due on the Storm Recovery Bonds together with the related Financing Costs. These related Financing Costs, or more specifically, On-going Financing Costs, include the servicing fee, administration fees for the SPE, rating agencies' fees, trustee fees and expenses, legal and accounting fees, other ongoing fees and expenses and the cost of replenishing the Capital Subaccount (or overcollateralization subaccount, if required). These On-going Financing Costs are "financing costs" eligible for recovery pursuant to the Securitization Statute and are addressed further below in this Financing Order.

DEC has proposed that the Storm Recovery Charges will be calculated and adjusted pursuant to the formula-based method, the True-Up Mechanism, described in witness Shana W. Anger's testimony and included as Appendix B to this Financing Order. DEC has requested approval of Storm Recovery Charges sufficient to recover the principal and interest on the Storm Recovery Bonds plus On-going Financing Costs. DEC proposes that the Storm Recovery Charges be adjusted at least semi-annually until 12 months prior to the last scheduled payment date of a series of the Storm Recovery Bonds, at which point the Storm Recovery Charges shall be adjusted at least quarterly, to ensure that the amount collected from Storm Recovery Charges is sufficient to pay the debt service on the Storm Recovery Bonds and all On-going Financing Costs.

Witness Charles N. Atkins II states that DEC's proposed bond structure is designed to provide substantially level annual debt service and revenue requirements over the life of the bond issue and would result in declining Storm Recovery Charges over time, assuming growth in customer energy consumption, other factors being equal. The Commission finds

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DEC's proposed transaction structure reasonable, and compliant with the Securitization Statute. Moreover, portions of DEC's proposed transaction structure, described in this Financing Order, are necessary to enable the Storm Recovery Bonds to obtain the highest bond credit rating possible, with an objective of AAA or equivalent bond credit ratings, so as to further ensure that the proposed issuance of the Storm Recovery Bonds on behalf of DEC and the imposition of the Storm Recovery Charges will provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds and meet the Statutory Cost Objectives. Accordingly, DEC's issuance structure is hereby approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

Special Purpose Entity

Under DEC's financing structure, DEC will create one or more SPEs, each as a bankruptcy remote, Delaware LLC with DEC as its sole member, as set forth in the LLC Agreement discussed further below. Each SPE will be formed for the limited purpose of acquiring Storm Recovery Property from DEC, issuing Storm Recovery Bonds in one or more series (each of which may be issued in one or more tranches), and performing other activities relating thereto or otherwise authorized by the LLC Agreement. The rights, obligations, structure and restrictions described in this Financing Order with respect to the SPE are applicable to each such purchaser of Storm Recovery Property to the extent of the Storm Recovery Property acquired by it and the Storm Recovery Bonds issued by it.

DEC proposed (i) that the SPE(s) may issue Storm Recovery Bonds in an aggregate amount not to exceed the Securitizable Balance approved by this Financing Order and (ii) to pledge to an indenture trustee, as collateral for payment of the Storm Recovery Bonds,

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the Storm Recovery Property, including each SPE's right to receive the Storm Recovery Charges as and when collected, and other collateral described in the Indenture. The SPE(s) will not be permitted to engage in any other activities and will have no assets other than storm recovery property and related assets to support its obligations under the storm recovery bonds. DEC states that these restrictions on the activities of the SPE and restrictions on the ability of DEC to take action on the SPE's behalf are imposed to achieve the objective that the SPE will be bankruptcy-remote and not be affected by a bankruptcy of DEC or any affiliate or successor of DEC.

DEC proposed that the SPE will be managed by a board of managers with rights and duties set forth in its organizational documents. As long as the Storm Recovery Bonds remain outstanding, the SPE will have at least one independent manager with no organizational affiliation with DEC other than possibly acting as independent manager(s) for another bankruptcy-remote subsidiary of DEC or its affiliates. The SPE will not be permitted to amend the provisions of its LLC Agreement or other organizational documents that relate to bankruptcy-remoteness of the SPE without the consent of the independent manager(s). Similarly, the SPE will not be permitted to institute bankruptcy or insolvency proceedings or to consent to the institution of bankruptcy or insolvency proceedings against it, or to dissolve, liquidate, consolidate, convert, or merge without the consent of the independent manager(s). Other restrictions to facilitate bankruptcy-remoteness may also be included in the organizational documents of the SPE as required by the rating agencies. The Commission agrees with DEC that these restrictions are reasonable and help ensure that the SPEs are bankruptcy-remote.

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The SPE will have no staff to perform administrative services (such as routine corporate maintenance, reporting and accounting functions). DEC proposed that these services will be provided by DEC pursuant to the terms of the Administration Agreement between the SPE and DEC.

Per rating agency and IRS requirements, DEC will transfer to the SPE an amount required to capitalize each of its SPEs adequately (the "SPE Capitalization Level") for deposit into the Capital Subaccount. The SPE Capitalization Level is expected to be 0.50 percent[15] of the initial principal amount of the Storm Recovery Bonds to be issued by the SPE or such greater amount as might be needed to meet IRS or rating agency requirements. The actual SPE Capitalization Level will depend on tax and rating agency requirements. The Commission finds that DEC may earn a return on this capital contribution in an amount equal to the rate of interest payable on the longest maturing tranche of Storm Recovery Bonds. Moreover, the Commission confirms that the SPE will be an "assignee" as defined in N.C. Gen. Stat. § 62-172(a)(2), when an interest in Storm Recovery Property is transferred, other than as security, to such SPE, and such SPE may issue Storm Recovery Bonds in accordance with this Financing Order as discussed further herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 10 & 11

Storm Recovery Property

The Commission determines, consistent with N.C. § 62-172(a)(15), that Storm Recovery Property consists of: (1) all rights and interests of DEC or any successor or assignee of DEC under this Financing Order, including the right to impose, bill, charge, collect, and receive storm recovery charges authorized in this Financing Order and to

[15] *See* IRS Rev. Proc. 2005-62 5.04(2).

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obtain true-up adjustments to such storm recovery charges as provided in this Financing Order, and (2) all revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in this Financing Order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

Pursuant to N.C. Gen. Stat. § 62-172(b)(3)c., DEC has requested that this Financing Order provide that the creation of the Storm Recovery Property will be conditioned upon, and simultaneous with, the sale of such Storm Recovery Property to the SPE and the pledge of such Storm Recovery Property to secure the Storm Recovery Bonds.

In addition, the Commission determines that the creation of Storm Recovery Property pursuant to this Financing Order is conditioned upon, and shall be simultaneous with, the sale or other transfer of the Storm Recovery Property to the SPE and the pledge of the Storm Recovery Property to secure the Storm Recovery Bonds.

The Storm Recovery Property shall constitute an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of Storm Recovery Charges depends on DEC performing its servicing functions relating to the collection of Storm Recovery Charges and on future electricity consumption. Such property shall exist regardless of whether or not the revenues or proceeds arising from the property have been billed, have accrued, or have been collected and notwithstanding the fact that the value or amount of the property is dependent on the future provision of service to retail customers by DEC or its successors or assignees and future consumption of

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electricity by retail customers. Furthermore, the Storm Recovery Property shall continue to exist until the Storm Recovery Bonds are paid in full and all Financing Costs and other costs of the Storm Recovery Bonds have been recovered in full.

The Storm Recovery Property also constitutes a present property right for purposes of contracts concerning the sale or pledge of property. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in the Storm Recovery Property, and in the revenue and collections arising from that property, is not subject to setoff, counterclaim, surcharge, or defense by DEC or any other person or in connection with the reorganization, bankruptcy, or other insolvency of DEC or any other entity. *See* N.C. Gen. Stat. § 62-172(e)(1).

The creation, attachment, granting, perfection, priority and enforcement of liens and security interests in Storm Recovery Property are governed by N.C. Gen. Stat. § 62-172(e)(2).

Pursuant to by N.C. Gen. Stat. § 62-172(e)(2)e., the priority of a security interest in Storm Recovery Property is not affected by the commingling of Storm Recovery Charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all Storm Recovery Charges that are deposited in the collection account or any other cash or deposit account of DEC in which Storm Recovery Charges have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when such funds are transferred to the collection account.

When DEC transfers Storm Recovery Property to the SPE pursuant to this Financing Order under an agreement that expressly states that the transfer is a sale or other absolute transfer in accordance with the "absolute transfer" provisions of N.C. Gen. Stat.

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§ 62-172(e)(3), that transfer shall constitute an absolute transfer and true sale and not a pledge of or secured transaction or other financing arrangement, and title (both legal and equitable) to the Storm Recovery Property shall immediately pass to the SPE. After such a transfer, the Storm Recovery Property shall not be subject to any claims of DEC or its creditors, other than creditors holding a properly perfected prior security interest in the Storm Recovery Property perfected by N.C. Gen. Stat. § 62-172(e).

As provided by N.C. Gen. Stat. § 62-172(e)(3)b., the characterization of the sale, conveyance, assignment, or transfer of Storm Recovery Property as an absolute transfer and true sale or other absolute transfer and the corresponding characterization of the transferee's property interest shall not be affected by: (1) commingling of Storm Recovery Charges arising with respect to the Storm Recovery Property with other amounts; (2) the retention by DEC of a (i) partial or residual interest, including an equity interest, in the Storm Recovery Property, whether direct or indirect, or whether subordinate or otherwise or (ii) the right to recover costs associated with taxes, franchise fees or license fees imposed on the collection of storm recovery charges; (3) any recourse that the transferee may have against DEC other than any such recourse created, contingent upon, or otherwise occurring or resulting from one or more of DEC's retail customers' inability to timely pay all or a portion of the Storm Recovery Charge; (4) any indemnification rights, obligations, or repurchase rights made or provided by DEC, other than indemnity or repurchase rights based solely upon DEC's retail customers' inability or failure to timely pay all or a portion of the Storm Recovery Charge; (5) the obligation of DEC to collect Storm Recovery Charges on behalf of the SPE; (6) DEC acting as the servicer of the Storm Recovery Charges or the existence of any contract that authorizes or requires DEC, to the extent that

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any interest in Storm Recovery Property is sold or assigned, to contract with the assignee or any financing party that it will continue to operate its system to provide service to its customers for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party; (7) the treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes; (8) granting or providing to holders of the Storm Recovery Bonds a preferred right to the Storm Recovery Property or credit enhancement by DEC or its affiliates with respect to the Storm Recovery Bonds; or (9) any application of the True-Up Mechanism.

The Commission finds that the terms and conditions discussed above regarding Storm Recovery Property are reasonable and adhere to the requirements of the Securitization Statute. In addition, the Storm Recovery Property and all other collateral is to be held and administered by an indenture trustee pursuant the Indenture, which helps ensure lower Storm Recovery Charges, and that the Statutory Cost Objectives can be achieved. Accordingly, the Commission approves of the (i) creation of Storm Recovery Property, including the rights to impose, bill, charge, collect and receive Storm Recovery Charges and obtain periodic adjustments to the Storm Recovery Charges and (ii) DEC's sale of the Storm Recovery Property to the SPE.

If DEC defaults on any required remittance of amounts collected in respect of Storm Recovery Property specified in this Financing Order, the Superior Court in Wake County, upon application by an interested party, and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the revenues arising from such Storm Recovery Property to the other financing parties. Any such order shall

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remain in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to DEC or its successors or assignees, provided; however, that in no circumstances shall the retail customers of DEC be responsible to pay storm recovery charges issued on behalf of DEP or the retail customers of DEP be responsible to pay the Storm Recovery Charges for Storm Recovery Bonds issued on behalf of DEC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

Transaction Documents

DEC has submitted in connection with its Joint Petition a form of the Purchase and Sale Agreement, the Administration Agreement, and the Servicing Agreement, which set out in substantial detail certain terms and conditions relating to the transaction structure for each issuance of Storm Recovery Bonds, including the proposed sale of Storm Recovery Property to the SPE, the administration of the SPE, and the servicing of the Storm Recovery Charges and Storm Recovery Bonds. DEC requested that we approve the substance of the form of the agreements between DEC and the SPE in connection with issuance of this Financing Order.

Drafts of these agreements were filed in order that this Commission may evaluate the principal rights and responsibilities of the parties thereto. The final versions of these agreements, however, will be subject to change based on the input from rating agencies, investors and other parties involved in the structuring and marketing of the Storm Recovery Bonds.

DEC has also submitted a form of Indenture between the SPE and an indenture trustee, which sets forth proposed security and terms for the Storm Recovery Bonds. DEC

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requested that we approve the substance of the Indenture, subject to such changes based on the input from rating agencies, investors and other parties involved in the structuring and marketing of the Storm Recovery Bonds.

DEC has also submitted a form of the LLC Agreement with DEC as the sole member that DEC proposed would constitute the organizing document of the SPE. DEC requested that we approve the substance of the LLC Agreement, which would be executed substantially in the form submitted to this Commission, subject to such changes as DEC deems necessary or advisable to satisfy bankruptcy opinion and rating agency considerations. In addition, DEC proposed to execute a Servicing Agreement with the SPE which may be amended, renewed, or replaced by another servicing agreement in accordance with its terms. DEC will be the initial servicer but may be succeeded as servicer as detailed in the Servicing Agreement. Pursuant to the Servicing Agreement, the servicer is required, among other things, to impose, bill, charge, collect and receive the Storm Recovery Charges for the benefit and account of the SPE, to make the periodic true-up adjustments of Storm Recovery Charges required or allowed by this Financing Order and to account for and remit its collection of Storm Recovery Charges to or for the account of the SPE in accordance with the remittance procedures contained in the Servicing Agreement without any charge, deduction, or surcharge of any kind, other than the servicing fee specified in the Servicing Agreement.

Under the Servicing Agreement, if any servicer fails to fully perform its servicing obligations, the indenture trustee or its designee may, and upon the instruction of the requisite percentage of holders of the outstanding bonds shall, appoint an alternate party to replace the defaulting servicer. The obligations of the servicer under the Servicing

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Agreement, the circumstances under which an alternate servicer may be appointed, and the conditions precedent for any amendment of such agreement will be more fully specified in the Servicing Agreement. The rights of the SPE under its Servicing Agreement will be included in the collateral pledged to the indenture trustee under its Indenture for the benefit of holders of the Storm Recovery Bonds and holders of the SRB Securities.

The Commission determines that the Transaction Documents described above are necessary to facilitate the proposed financing structure approved herein. Moreover, the Transaction Documents are reasonable and will help to achieve the Statutory Cost Objectives. Accordingly, the form Transaction Documents are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 13 & 14

Offering and Sale of the Bonds

DEC has proposed that the Storm Recovery Bonds be offered pursuant to an SEC-registered offering. The Company has provided testimony to the effect that virtually all utility securitizations have been sold as SEC-registered public transactions. Further, DEC has provided testimony to the effect that an SEC-registered, public offering, is likely to result in a lower cost of funds relative to a non SEC-registered offering, including a Rule 144A qualified institutional offering, all else being equal, due to the enhanced transparency and liquidity of publicly-registered securities. Accordingly, subject to the IAL procedure described further below, the Commission finds that an SEC-registered public offering is most likely to result in the lowest costs to consumers, and should be approved. However, the Commission further finds DEC, subject to the IAL procedures described in the Evidence and Conclusions for Finding of Fact No. 33, may also pursue a Rule 144A qualified institutional offering of the Storm Recovery Bonds.

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DEC has proposed that the Storm Recovery Bonds be sold pursuant to a sale to one or more underwriters in a negotiated offering as described in the testimony of witness Atkins. DEC, consistent with its other securities offerings, will select the lead managing underwriter(s) to achieve its Statutory Cost Objectives. DEC has testified that a negotiated underwriting is likely to provide greater flexibility and availability of investor funds.

The Commission finds, subject to the IAL procedures, that the issuance of the Storm Recovery Bonds pursuant to an SEC-registered negotiated sale is likely to result in lower overall costs and satisfy the Statutory Cost Objectives, and should therefore be approved. However, DEC, subject to the IAL procedures, is also authorized to pursue other sale options, including a Rule 144A offering, in order to satisfy the Statutory Cost Objectives. The Commission therefore finds it necessary to grant DEC flexibility and authority to pursue other sale options that result in the lowest Storm Recovery Charges for customers consistent with market conditions at the time the Storm Recovery Bonds are priced.

DEC has testified that the SPE may, as an alternative to directly issuing and marketing the Storm Recovery Bonds to unaffiliated investors through either a registered public offering or unregistered exempt offering, issue the Storm Recovery Bonds to a single special purpose trust, the SRB Issuer, established jointly by DEC and DEP or by Duke Energy Corporation.

In this case, notes or similar instruments would be issued by the SRB Issuer to investors backed by the SPE's Storm Recovery Bonds and storm recovery bonds issued by an SPE wholly-owned by DEP pursuant to DEP's financing order held by the SRB Issuer (the "SRB Securities"). The SRB Issuer would engage in no activities other than the

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holding of the Storm Recovery Bonds and the storm recovery bonds issued by an SPE wholly-owned by DEP, issuing the SRB Securities and engaging in other related activities. A form of the proposed Declaration of Trust is attached to the testimony of witness Heath as Heath Exhibit 2f and co-sponsored by witness Atkins. DEC asks the Commission to approve the substance of the Declaration of Trust, subject to such changes based on input from rating agencies, investors and other parties involved in the structuring and marketing of the SRB Securities.

The SRB Securities would be sold either through a registered public offering or unregistered exempt offering described above. The SRB Securities would be structured in order to achieve the highest possible credit rating from applicable rating agencies based upon the underlying structure of the SRB Issuer secured by Storm Recovery Property and the storm recovery property owned by a SPE wholly-owned by DEP and supported by the True-Up Mechanism.

Combining the issuance of DEC's Storm Recovery Bonds and DEP's storm recovery bonds in one transaction through the use of the SRB Issuer will likely, as detailed in the testimony of witness Atkins and witness Heath, result in enhanced marketability and other efficiencies, thereby lowering costs for both DEC's and DEP's customers. None of the SPEs would be obligated, however, with respect to any other SPE's storm recovery bonds; therefore, the customers of DEC would not be affected by the actions of DEP or the adequacy of the storm recovery property of DEP. The SRB Issuer would transfer an allocable portion of net proceeds from the sale of the SRB Securities to each SPE and each such SPE would in turn transfer those proceeds to DEC or DEP, as applicable in consideration for the storm recovery property sold to such SPE by DEC or DEP.

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The Commission finds the testimony of witness Heath and witness Atkins to be persuasive, and agrees that combining the issuance of DEC's Storm Recovery Bonds and DEP's storm recovery bonds in one transaction through the use of the SRB Issuer may result in lower Storm Recovery Charges for customers, and help ensure that the Statutory Cost Objectives can be met. Accordingly, the Commission hereby grants DEC the authority in this Financing Order to issue Storm Recovery Bonds in a combined transaction with DEP through the use of the SRB Issuer. By allowing the Companies flexibility to determine which of the above issuance structures are best tailored to then-existing rating agency considerations, market conditions, and investor preferences, the financing of Storm Recovery Costs can be reasonably expected to result in the lowest Storm Recovery Charges consistent with market conditions at the time the Storm Recovery Bonds are priced.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 15—17

Amortization, Interest Rates, and Credit Ratings of Storm Recovery Bonds

Regarding the principal amortization, the Commission determines that the expected term of the scheduled final payment date of the last maturing tranche should be no later than 15 years from the issuance of the series of Storm Recovery Bonds. The legal maturity date of each tranche may be longer than the scheduled final payment date for that tranche. Annual payments of principal of and interest on the Storm Recovery Bonds shall be substantially level over the expected term of the Storm Recovery Bonds.

The first payment of principal and interest for each series of Storm Recovery Bonds shall occur within 12 months of issuance. Payments of principal and interest thereafter shall be no less frequent than semi-annually. The Commission finds that this proposed

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structure—providing substantially level annual debt service and revenue requirements over the life of the Storm Recovery Bonds—is in the public interest and should be utilized.

As to interest rates, the Commission determines that each tranche of the Storm Recovery Bonds should have a fixed interest rate, based on current market conditions. If market conditions change, and it becomes necessary to achieve the Statutory Cost Objectives for the one or more tranches of bonds to be issued in floating-rate mode, DEC is authorized to issue such bonds but will be required to execute agreements to swap the floating payments to fixed-rate payments. This flexibility will ensure that DEC can achieve economic benefits for customers.

The Company anticipates that each series of Storm Recovery Bonds will have a AAA or equivalent rating from at least two nationally recognized rating agencies. The Commission hereby grants DEC authority to provide necessary credit enhancements, with recovery of related costs as a form of On-going Financing Costs, to achieve such ratings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

Security for Storm Recovery Bonds

DEC proposed that the payment of the Storm Recovery Bonds and related Storm Recovery Charges authorized by this Financing Order is to be secured by the Storm Recovery Property created by this Financing Order and by certain other collateral as described herein. The Storm Recovery Bonds will be issued pursuant to an Indenture under which the indenture trustee will administer the trust.

DEC proposed that the SPE will establish a Collection Account as a trust account to be held by its indenture trustee as collateral to facilitate the payment of the principal of, interest on, and On-going Financing costs related to, the Storm Recovery Bonds in full and

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on a timely basis. Each Collection Account will include the General Subaccount, the Capital Subaccount and the Excess Funds Subaccount, and may include other subaccounts if required to obtain AAA ratings on the Storm Recovery Bonds.

DEC proposes that Storm Recovery Charge remittances from the servicer with respect to the Storm Recovery Bonds will be deposited into the General Subaccount for the SPE. On a periodic basis, the money in the General Subaccount will be allocated to pay expenses of the SPE, to pay principal of and interest on the Storm Recovery Bonds, and to meet the funding requirements of the other subaccounts, according to specified payment priority established in the Indenture. Funds in the General Subaccount will be invested by the indenture trustee in short-term, high-quality investments and such funds (including, to the extent necessary, investment earnings) will be applied by the indenture trustee to pay principal of and interest on the Storm Recovery Bonds and all other components of the On-going Financing Costs payable by the SPE.

When the Storm Recovery Bonds are issued, DEC proposes that it will make a capital contribution to its SPE, which the SPE will deposit into its Capital Subaccount. The storm recovery proceeds will not be used to fund this capital contribution. The amount of the capital contribution will be at least 0.5 percent of the original principal amount of the Storm Recovery Bonds issued by the SPE. Each Capital Subaccount will serve as collateral to facilitate timely payment of principal of and interest on the Storm Recovery Bonds. To the extent that a Capital Subaccount must be drawn upon to pay these amounts due to a shortfall in the Storm Recovery Charge collections, it will be replenished to its original level through the true-up process described below. The funds in each Capital Subaccount will be invested in short-term, high-quality investments and, if necessary, such funds

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(including investment earnings) will be used by the indenture trustee to pay principal of and interest on the Storm Recovery Bonds and the On-going Financing Costs payable by the SPE. DEC will be permitted to earn a rate of return on its invested capital in the SPE equal to the rate of interest payable on the longest maturing tranche of Storm Recovery Bonds and this return on invested capital should be a component of the Periodic Payment Requirement (as defined below), and accordingly, recovered from Storm Recovery Charges.

DEC proposed that any Excess Funds Subaccount will hold any Storm Recovery Charge collections and investment earnings on the Collection Account in excess of the amounts needed to pay current principal of and interest on the Storm Recovery Bonds and to pay all of the On-going Financing Costs payable by the SPE including, but not limited to, funding or replenishing each Capital Subaccount. Any balance in or amounts allocated to such Excess Funds Subaccount on a true-up adjustment date will be subtracted from any amounts required for such period for purposes of the true-up adjustment. The funds in the Excess Funds Subaccount will be invested in short-term, high-quality investments, and such funds (including investment earnings thereon) will be available to pay principal of and interest on the Storm Recovery Bonds and the On-going Financing Costs payable by the SPE.

DEC also proposed that any Collection Account and the subaccounts described above are intended to facilitate the full and timely payment of scheduled principal of and interest on the Storm Recovery Bonds and all other authorized components of the On-going Financing Costs payable by the SPE. If the amount of Storm Recovery Charge collections in the General Subaccount is insufficient to make, on a timely basis, all scheduled payments

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of principal of and interest on the Storm Recovery Bonds and to make payment on all of the other components of the On-going Financing Costs payable by the SPE, the relevant Excess Funds Subaccount and the relevant Capital Subaccount will be drawn down, in that order, to make such payments. Any deficiency in a Capital Subaccount due to such withdrawals must be replenished on a periodic basis through the true-up process.

In addition to the foregoing, there may be such additional accounts and subaccounts as are necessary to segregate amounts received from various sources, or to be used for specified purposes. Upon the maturity of the Storm Recovery Bonds and upon the discharge of all obligations with respect to such bonds, amounts remaining in each Collection Account will be released to the appropriate SPE and will be available for distribution by the SPE to DEC. As noted in this Financing Order, equivalent amounts, less the amount of any Capital Subaccount, will be booked to a regulatory liability and credited back to customers in the Company's next rate case following the maturity of the Storm Recovery Bonds.

Based upon the foregoing, the Commission finds that utilization of a Collection Account, including a General Subaccount, a Capital Subaccount and an Excess Funds Subaccount, as proposed by DEC is reasonable and should help achieve the Statutory Cost Objectives. Moreover, it is necessary to grant DEC the flexibility and authority to include other subaccounts in the Collection Account where required to obtain AAA ratings on the series of Storm Recovery Bonds, which will in turn lower Storm Recovery Charges for customers.

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 19 & 20

DEC as Initial Servicers of the Storm Recovery Bonds

DEC proposes to execute a Servicing Agreement with the SPE, the final version of which shall be filed with this Commission concurrent with its filing with the SEC.

Under the Servicing Agreement, the servicer shall be required, among other things, to impose, bill, charge, collect and receive the Storm Recovery Charges for the benefit of its SPE, to make the true-up adjustments of Storm Recovery Charges required or allowed by this Financing Order, and to account for and remit the Storm Recovery Charges to or for the account of its SPE in accordance with the remittance procedures contained in the Servicing Agreement without any charge, deduction, or surcharge of any kind, other than the servicing fee specified in the Servicing Agreement. The appropriate servicing fee shall be as set forth in this Financing Order.

To preserve the integrity of the bankruptcy-remote structure of the SPE and ensure the high credit quality of the Storm Recovery Bonds, the servicer must be adequately compensated for the services it provides, including the calculation, billing, and collection of Storm Recovery Charges, remittance of those charges to the indenture trustee, and the preparation, filing, and processing of the TUAL. DEC's proposed form of Servicing Agreement provides for an on-going servicing fee for the initial servicer in the amount of 0.05 percent of the initial principal amount of the Storm Recovery Bonds plus out-of-pocket expenses. DEC has submitted testimony on the costs anticipated to be incurred by it in connection with the servicing functions under the Servicing Agreement, and we find such costs to be reasonable and appropriate.

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DEC's proposed form of Servicing Agreement provides for an annual fee for on-going services of 0.05 percent of the initial principal amount of the Storm Recovery Bonds so long as DEC acts as servicer plus out-of-pocket expenses. In addition to the annual on-going servicing fee, DEC proposes to recover as an Up-front Financing Cost, approximately $5.2 million, to recover set-up costs of the servicer, including information technology programming costs to adapt DEC's existing systems to bill, charge, collect, receive and process Storm Recovery Charges, and to set up necessary servicing functions. The evidence shows that these amounts represent a prudently incurred cost to DEC, and we find that those costs are reasonable.

However, the servicing fees collected by DEC, or any affiliate acting as the servicer under the Servicing Agreement, will be reflected in DEC's ongoing cost of service such that any amounts in excess of DEC's incremental costs of servicing the Storm Recovery Bonds shall be returned to DEC's retail customers in the Company's next rate case. The expenses incurred by DEC or such affiliate to perform obligations under the Servicing Agreement not otherwise recovered through the Storm Recovery Charges will likewise be included in DEC's cost of service.

DEC has proposed that it will not be permitted voluntarily to resign from its duties as a servicer if the resignation will harm the credit rating on Storm Recovery Bonds issued by its SPE. Even if DEC's resignation as servicer would not harm the credit rating on the Storm Recovery Bonds issued by the SPE, we find and direct that DEC shall not be permitted to voluntarily resign from its duties as servicer without consent of the Commission. If DEC defaults on its duties as servicer or is required for any reason to discontinue those functions, then DEC proposes that a successor servicer acceptable to the

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indenture trustee be named to replace DEC as servicer so long as such replacement would not cause any of the then current credit ratings of the Storm Recovery Bonds to be suspended, withdrawn or downgraded. We find that any successor servicer to DEC also should be acceptable to the Commission.

DEC has proposed that, and we find and direct that, the servicing fee payable to a substitute servicer should not exceed 0.60 percent per annum on the initial principal balance of the Storm Recovery Bonds issued by the SPE, unless a higher fee is approved by the Commission.

DEC shall indemnify its retail customers to the extent retail customers incur losses associated with higher servicing fees payable to a substitute servicer as a result of DEC's negligence, recklessness or willful misconduct in acting as a servicer. This indemnification provision shall be reflected in the Transaction Documents for these Storm Recovery Bonds.

We find and direct that the SPE and the indenture trustee shall not be permitted to waive any material obligations of DEC as transferor or as servicer of Storm Recovery Property without express written consent of this Commission.

Furthermore, it is contemplated that DEC shall act as the servicer for the Storm Recovery Bonds until the Storm Recovery Bonds are fully amortized. If the State of North Carolina or this Commission decides to allow billing, collection, and remittance of the Storm Recovery Charges by a third party supplier within the DEC service territory, such authorization must be consistent with the rating agencies' requirements, as outlined in the testimony of witness Atkins necessary for the Storm Recovery Bonds to maintain the targeted AAA or equivalent rating.

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The Commission finds and concludes that it is reasonable for DEC to act as initial servicer under the proposed financing transaction and that such will reduce risk associated with the proposed securitization therefore resulting in lower Storm Recovery Charges and greater benefits to ratepayers. Accordingly, this Financing Order grants DEC authority and flexibility to act as initial servicer pursuant to the Servicing Agreement under the proposed financing structure.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 21 & 22

DEC Administrator of the SPE

Under the above-described Administration Agreement, DEC will perform the administrative duties necessary to maintain the SPE. The appropriate administration fee shall be as set forth in this Financing Order.

DEC's proposed form of Administration Agreement provides for a $50,000 annual fee plus out-of-pocket expenses paid to an administrator for performing the services required by the Administration Agreement. Witness Heath discusses the costs anticipated to be incurred by it in connection with the Administration Agreement in his testimony. We find that DEC has demonstrated that this annual fee is necessary to cover any costs to be incurred by DEC in performing services as administrator.

The Commission finds and concludes that it is reasonable for DEC to act as an administrator of the SPE under the proposed financing transaction. Accordingly, this Financing Order grants DEC authority and flexibility to act as administrator pursuant to the Administration Agreement under the proposed financing structure.

The administration fees collected by DEC or any affiliate acting as the administrator under the Administration Agreement will be included in DEC's cost of

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service such that any amounts in excess of DEC's incremental costs of administering the SPE shall be returned to DEC's retail customers. The expenses incurred by DEC or such affiliate to perform obligations under the Administration Agreement not otherwise recovered through the Storm Recovery Charges will likewise be included in DEC's cost of service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 23 & 24

On-going Financing Costs

Heath Exhibit 1, attached to the testimony of witness Heath, provides an estimate of the On-going Financing Costs associated with the Storm Recovery Bonds, which DEC proposes to recover through the Storm Recovery Charge. DEC's On-going Financing Costs include, without limitation, rating agency surveillance fees, servicing fees, administration fees, legal and auditing fees, regulatory assessment fees, trustee fees, independent manager(s) fees and the return on invested capital.

Certain of these On-going Financing Costs, such as the administration fees and the amount of the servicing fees for DEC (as the initial servicer) are determinable, either by reference to an established dollar amount or a percentage as discussed above, on or before the issuance of the Storm Recovery Bonds. Other On-going Financing Costs will vary over the term of the Storm Recovery Bonds.

Having reviewed DEC's proposal, the Commission determines that the proposed On-going Financing Costs identified in DEC's Joint Petition and Attachment 4 of the form of IAL qualify as "financing costs" pursuant to N.C. Gen. Stat. § 62-172(a)(4) and are therefore eligible for recovery through a storm recovery charge. Additionally, consistent with the Commission's conclusions for Finding of Fact Nos. 20 and 22, the Commission

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reiterates that it is appropriate for DEC to credit back to customers all periodic servicing and administration fees in excess of DEC's or an affiliate of DEC's incremental cost of performing the servicer or administrator function in the next rate case when costs and revenues associated with the servicing and administration fees will be included in DEC's cost of service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

Storm Recovery Bonds to Be Treated as "Debt" for Federal Income Tax Purposes

In light of the IRS safe harbor rules, we find that DEC shall be responsible to structure the Storm Recovery Bond transactions in a way that clearly meets all requirements for the IRS' safe harbor treatment, including that, for federal income tax purposes, the Storm Recovery Bonds shall be treated as debt of DEC.

STORM RECOVERY CHARGES

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 26—29

Imposition and Computation of Storm Recovery Charges

DEC seeks authorization to collect from its customers, in the manner provided in this Financing Order and/or the Tariffs approved hereby, Storm Recovery Charges in an amount sufficient to provide for the timely payment of principal of and interest on the Storm Recovery Bonds and all other On-going Financing Costs as described in the Evidence and Conclusions for Finding of Fact Nos. 23 & 24.

To repay the Storm Recovery Bonds and On-going Financing Costs, DEC is hereby authorized to implement Storm Recovery Charges to be collected on a per-kWh basis from all applicable customer rate classes until the Storm Recovery Bonds and associated Financing Costs are paid in full. The Storm Recovery Charges are nonbypassable, and must be paid by all existing or future retail customers receiving transmission or distribution

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services from DEC or its successors or assignees under Commission-approved rate schedules or under special contracts, even if the retail customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in this state. *See* N.C. Gen. Stat. § 62-172(a)(13) and (b)(3)b.4. In the event there is a fundamental change in the regulation of public utilities, the Storm Recovery Charges shall be collected in a manner that will not adversely affect the rating on the Storm Recovery Bonds.

In summary, the Securitization Statute provides for the recovery of storm recovery costs through storm recovery bonds. Accordingly, to compute the Storm Recovery Charges, DEC first applied the allocation factors to the total first year revenue requirements as presented in witness Abernathy DEC Exhibit 3 in order to allocate the revenue requirements to each customer rate class. These revenue requirements were grossed-up to reflect uncollectible account write-offs and the regulatory fees to arrive at the storm recovery revenue requirements by rate class. Next, the rate was calculated by dividing total revenue requirements for each customer rate class by the effective kWh sales forecast for each customer rate class.

DEC applied the allocation factors to the customer rate classes in the manner in which these costs or their equivalent costs were allocated in the cost-of-service study proposed by DEC in Docket No. E-7, Sub 1214, as required by the Securitization Statute. DEC used the allocation factors as well as the sales forecast (based on the 2021 retail sales forecast filed in the Company's most recent Integrated Resource Plan) to calculate the proposed initial Storm-Recovery Charge per kWh by customer rate class. The resulting

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Storm Recovery Charges were then set forth in proposed Tariffs, as shown in witness Jonathan Byrd's Exhibit 2, needed to implement the Storm Recovery Charge.

A formula-based mechanism as described in N.C. Gen. Stat. § 62-172(b)(3)b.6., the True-Up Mechanism, to calculate, and adjust from time to time, the Storm Recovery Charges for each customer rate class was submitted by DEC. DEC submitted with the Joint Petition the supporting testimony of witness Angers, which provided the True-Up Mechanism to determine the Periodic Payment Requirement (defined further below) to be recovered from the Storm Recovery Charge. This True-Up Mechanism is attached as Appendix B.

DEC also submitted with its Joint Petition the supporting testimony of witness Byrd with respect to allocation of these periodic costs and the computation of the Storm Recovery Charges for each customer rate class for DEC. As discussed in the testimony of witness Abernathy and shown in Abernathy DEC Exhibits 1-4, DEC computed the estimated Storm Recovery Charges, as described in N.C. Gen. Stat. § 62-172(a)(13).

We hereby find that the cost allocation formula described in DEC's testimony and embedded in the True-Up Mechanism is consistent with N.C. Gen. Stat. § 62-172(b)(3)b.6. and is reasonable.

In the event DEC chooses to issue Storm Recovery Bonds to a trust or another SPE, as described in Finding of Fact No. 14, the obligations of customers of DEC to pay relevant storm recovery bonds shall not be joint and several with customers of the other utility meaning that each storm recovery charge shall only be adjusted pursuant to the True-up Mechanism to ensure the collection of amounts sufficient to pay principal of, interest on and other on-going financing costs related to the relevant storm recovery bonds.

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In N.C. Gen. Stat. § 62-172(k), the State pledges to and agrees with the bondholders, the owners of Storm Recovery Property, and other financing parties that the State and its agencies, including this Commission will not: (1) alter the provisions of the Securitization Statute, which authorize this Commission to create an irrevocable contract right or chose in action by the issuance of this Financing Order irrevocable binding, or nonbypassable charges, to create Storm Recovery Property, and make the Storm Recovery Charges imposed by this Financing Order; (2) take or permit any action that impairs or would impair the value of Storm Recovery Property or revises the Storm Recovery Costs for which recovery is authorized; (3) in any way impair the rights and remedies of the bondholders, assignees, and other financing parties; or (4) except for changes made pursuant to the True-Up Mechanism, reduce, alter, or impair Storm Recovery Charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related Storm Recovery Bonds have been paid and performed in full. This Commission finds that this State Pledge will constitute a contract with the bondholders, the owners of Storm Recovery Property, the SRB Issuer, holders of SRB Securities and other financing parties.

This Commission anticipates stress case analyses, as described in witness Atkins' testimony, will show that the broad-based nature of the True-Up Mechanism under N.C. Gen. Stat. § 62-172(b)(3)b.6., and the State Pledge under N.C. Gen. Stat. § 62-172(k), will serve to minimize credit risk associated with the Storm Recovery Bonds (i.e., that sufficient funds will be available and paid to discharge the principal and interest when due).

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 30 & 31

Treatment of Storm Recovery Charge in Tariff and on Retail Customer Bills

DEC submitted a proposed Tariff included as Byrd DEC Exhibit 2 attached to witness Byrd's testimony to impose the Storm Recovery Charge. Pursuant to N.C. Gen. Stat. § 62-172(d)(1), the tariffs must "explicitly reflect that a portion of the charges on such bill represents storm recovery charges approved in a financing order issued to the public utility and, if the storm recovery property has been transferred to an assignee, must include a statement to the effect that the assignee is the owner of the rights to storm recovery charges and that the public utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee." In addition, the "tariff applicable to customers must indicate the storm recovery charge and the ownership of the charge." N.C. Gen. Stat. § 62-172(d)(1).

The Commission finds that DEC's proposed Tariff included as Byrd DEC Exhibit 2 and attached to witness Byrd's testimony include the required language necessary to effectuate N.C. Gen. Stat. § 62-172(d) and is hereby approved.

In addition, and in accordance with N.C. Gen. Stat. § 62-172(d)(2), the Commission determines that DEC's applicable Storm Recovery Charge must be recognized as a separate line item on retail customer bills entitled Storm Securitization Charge and include both the rate and the amount of the charge. Moreover, all electric bills issued by DEC must state that, as approved in a financing order, all rights to the Storm Recovery Charge are owned by the SPE and that DEC is acting as collection agent or servicer for its SPE.

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

True-Up of Storm Recovery Charges

Pursuant to N.C. Gen. Stat. § 62-172(b)(3)b.6., the servicer of the Storm Recovery Property will file for standard true-up adjustments to the Storm Recovery Charges at least semi-annually to ensure Storm Recovery Charge collections are sufficient to provide for the timely payment of the principal of and interest on the Storm Recovery Bonds and of all of the On-going Financing Costs payable by the SPE in respect of Storm Recovery Bonds as approved under this Financing Order. This required periodic payment of all such amounts will also include deficiencies on past due amounts for any reason for a series of Storm Recovery Bonds.

Pursuant to N.C. Gen. Stat. § 62-172(b)(3)b.6., this Financing Order must include a formula-based true-up mechanism for making expeditious periodic adjustments in the Storm Recovery Charges that retail customers are required to pay pursuant to this Financing Order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of the Periodic Payment Requirement (as defined below).

Consistent with Section N.C. Gen. Stat. § 62-172(b)(3)d., DEC proposed to file with the Commission at least semi-annually (and at least quarterly beginning 12 months prior to the last scheduled payment date for the latest maturing tranche of a series of Storm Recovery Bonds) a letter applying the formula-based True-Up Mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make the necessary adjustments.

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In addition to the semi-annual true-up adjustments, DEC proposed that the servicer of the Storm Recovery Property also be authorized to make optional interim true-up adjustments at any time and for any reason in order to ensure the recovery of revenues sufficient to provide for the timely payment of Periodic Payment Requirement.

The Commission accepts the Company's true-up proposals as reasonable, and finds that DEC shall adhere to the following requirements:

After issuance of Storm Recovery Bonds on behalf of DEC, the servicer will submit at least semi-annually (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of a series of Storm Recovery Bonds) a letter in this docket for Commission review, as described in N.C. Gen. Stat. § 62-172(b)(3)d., and in the form attached hereto as Appendix B.

The TUAL will apply the formula-based True-Up Mechanism described herein and in Appendix B to this Financing Order for making expeditious periodic adjustments in the relevant Storm Recovery Charge to correct for any over-collection or under-collection of the charges or to otherwise ensure the timely payment of the Periodic Payment Requirement for each series of Storm Recovery Bonds.

The "Periodic Payment Requirement" will be composed of the following components for each collection period: (i) the payments of the principal of and interest on the Storm Recovery Bonds issued by the SPE, in accordance with the expected amortization schedule, including deficiencies on past-due principal and interest for any reason, (ii) On-going Financing Costs payable during the collection period and the costs of funding and/or replenishing the Capital Subaccount and any other credit enhancements

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established in connection with the Storm Recovery Bonds and other related fees and expenses.

The first Periodic Payment Requirement established through the IAL procedures may be calculated based upon a set of collection periods greater or less than twelve collection periods. Notwithstanding the foregoing, in the event that any Storm Recovery Bonds are outstanding following the last scheduled payment date for the tranche of the latest maturing series of Storm Recovery Bonds, the Periodic Payment Requirement will be calculated so that collections are sufficient to make all payments on those Storm Recovery Bonds, and in respect of Financing Costs, no later than the immediately following payment date.

Along with each TUAL, the servicer shall provide workpapers showing all inputs and calculations, including its calculation of the Storm Recovery Charge and by customer rate class. Pursuant to N.C. Gen. Stat. § 62-172(b)(3)d., the Commission, upon the filing of a TUAL made pursuant to this Financing Order, shall render an administrative approval of the request or inform the servicer of any mathematical or clerical errors in its calculation as expeditiously as possible, but no later than 30 days following the servicer's true-up filing. Notification and correction of any mathematical or clerical errors shall be made so that the true-up is implemented within 30 days of the servicer's true-up filing. If no action is taken within 30 days of the filing of the TUAL, the true-up calculation shall be deemed approved. Upon approval or the passage of 30 days without notification of a mathematical or clerical error, no further action of this Commission will be required prior to implementation of the true-up.

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To ensure adequate Storm Recovery Charge collections and to avoid large over-collections and under-collections over time, we direct that the servicer shall reconcile Storm Recovery Charges using DEC's most recent forecast of electricity deliveries (i.e., forecasted billing units and Commission-approved customer class allocations) used for all corporate purposes and DEC's estimates of related expenses. Each periodic true-up adjustment should ensure that Storm Recovery Charge collections are sufficient to meet the Periodic Payment Requirement. The calculation of the Storm Recovery Charges will also reflect both a projection of uncollectible Storm Recovery Charges and a projection of payment lags between the billing and collection of Storm Recovery Charges based upon DEC's most recent experience regarding collection of Storm Recovery Charges.

This Commission hereby approves the True-Up Mechanism and determines that each TUAL shall be based upon the cumulative differences, regardless of the reason, between the Periodic Payment Requirement (including scheduled principal and interest payments on the Storm Recovery Bonds) and the amount of Storm Recovery Charge collections and estimated Storm Recovery Charge collections to the indenture trustee.

ISSUANCE ADVICE LETTER

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

DEC shall file a combined IAL/TUAL in final form with the Commission within one business day after actual pricing. As shown in the form of IAL/TUAL, the combined IAL/TUAL shall include the following information: the actual structure of the Storm Recovery Bond issuance; the scheduled final payment dates and legal maturities of the Storm Recovery Bonds shall be under the direct control of DEC and its counsel at the Company's sole discretion; over-collateralization levels (if any); any other credit

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enhancements; revised estimates of the Up-front Financing Costs proposed to be financed and estimates of debt service and other On-going Financing Costs for the first collection period and other information specific to the Storm Recovery Bonds from proceeds of the Storm Recovery Bonds. Finally, the combined IAL/TUAL shall include certifications from DEC, if required, that the structuring and pricing of the Storm Recovery Bonds achieved the Statutory Cost Objectives. The actual details of the transaction, including certifications from DEC, included with the IAL/TUAL shall be provided no later than the first business day after pricing (unless the Commission, acting through its representatives agree to a longer time). Unless the Commission issues an order stopping the Storm Recovery Bond issuance before noon on the third business day after pricing because the Commission determines that the IAL/TUAL and all required certifications have not been delivered or the transaction does not comply with the Standards of this Financing Order, the transaction proceeds without any further action of this Commission. The Commission shall only issue an order to stop the transaction if the Commission determines that (a) the transaction does not comply with the Standards of this Financing Order, or (b) DEC has not delivered the required certification in a form acceptable to the Commission. However, this Commission retains discretion either to allow the transaction to be completed or to issue an order to stop the transaction if DEC fails to deliver the required certification or is unable or unwilling to deliver the required certification in a form acceptable to this Commission. The Commission will not issue an order to stop the transaction for any other reason, including, but not limited to, a change in market conditions after the moment of pricing.

Prior to the filing of the IAL/TUAL and through the period ending with the issuance of the Storm Recovery Bonds, DEC will, to the extent requested by this Commission,

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provide this Commission or a designated Commissioner or member of Commission Staff (the "Designated Member") with timely information so that the Commission acting for itself or through its Designated Member can participate fully and in advance regarding all material aspects relating to the structuring and pricing of , and Financing Costs relating to the Storm Recovery Bonds.

DEC will retain sole discretion regarding whether or when to assign, sell or otherwise transfer any rights concerning Storm Recovery Property arising under this Financing Order, or to cause the issuance of any Storm Recovery Bonds authorized in this Financing Order; *provided*, that any issuance must satisfy the Statutory Costs Objectives. Subject to the IAL procedures described above, the SPE will issue the Storm Recovery Bonds on or after the fifth business day after pricing of the Storm Recovery Bonds.

In the event either (i) DEC determines that the issuance of the Storm Recovery Bonds would not achieve the Statutory Cost Objectives or (ii) the Commission will not permit issuance of the Storm Recovery Bonds by issuing an order to stop the transaction in accordance with the IAL procedures, then DEC shall not be precluded from seeking to recover Financing Costs incurred and Carrying Costs accrued post issuance of the DEC Rate Order.

MITIGATION OF RATE IMPACTS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

N.C. Gen. Stat. § 62-172(b)(1)g., requires a public utility petitioning the Commission for a financing order to provide "a comparison between the net present value of the costs to customers that are estimated to result from the issuance of storm recovery bonds and the costs that would result from the application of the traditional method of

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financing and recovering storm recovery costs from customers." In addition, N.C. Gen. Stat. § 62-172(b)1.g. requires a public utility petitioning the Commission for a financing order to demonstrate that "the comparison should demonstrate that the issuance of storm recovery bonds and the imposition of storm recovery charges are expected to provide quantifiable benefits to customers."

In the DEC Settlement, DEC and the Public Staff agreed that to demonstrate quantifiable benefits to customers in accordance with N.C. Gen. Stat. § 62-172(b)(1)g., that DEC must show that the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery. For purposes of settlement, DEC and the Public Staff also agreed on the assumptions to be used in evaluating whether securitization of the Storm Recovery Costs provides quantifiable customer benefits when compared to traditional storm cost recovery. Specifically, the DEC Settlement requires that when conducting this comparison, DEC will make the following assumptions in determining what the "new rates" under the traditional method of recovery would have been absent the issuance of the Storm Recovery Bonds:

1) for traditional storm cost recovery, 12 months of amortization for each Storm was expensed prior to the new rates associated with traditional storm cost recovery going into effect;

2) for traditional storm cost recovery, no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance;

3) for traditional storm cost recovery, no carrying charges were accrued on the deferred balance during the 12-month period following the dates of the Storms;

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4) for traditional storm cost recovery, the amortization period for the Storms is a minimum of 10 years; and

5) for an issuance of storm recovery bonds, the imposition of the storm recovery charges begins nine months after the new rates associated with traditional storm cost recovery would go into effect.

DEC provided the cost comparison required by N.C. Gen. Stat. § 62-172(b)(1)g. in witness Abernathy's DEC Exhibit 5. Abernathy DEC Exhibit 5 calculates both the total estimated net present value of costs to customers under the Storm Recovery Charges as well as the total cumulative costs to customers under the traditional cost recovery method. In addition, witness Abernathy included the aforementioned DEC Settlement assumptions in Abernathy DEC Exhibits 5-7, and explained in her testimony that the Company utilized the assumptions and adhered to the DEC Settlement in calculating its costs for the comparison. Therefore, as an initial matter, the Commission concludes that DEC has provided the necessary comparison required by N.C. Gen. Stat. § 62-172(b)(1)g. and properly adhered to the DEC Settlement.

As shown in Abernathy DEC Exhibit 5, using the traditional method of cost recovery, the net present value of total retail costs to customers is approximately $180 million. Using the storm securitization method of cost recovery and recovering Storm Recovery Costs through the Storm Recovery Charge, the net present value of total retail costs to customers is approximately $122 million. This results in approximately $58 million, or approximately 32.0 percent, in quantifiable benefits to customers. The calculation of these costs are detailed in Abernathy DEC Exhibits 5, 6 and 7.

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Thus, we find that the issuance of the Storm Recovery Bonds and the imposition of the Storm Recovery Charges authorized by this Financing Order have a significant likelihood of providing quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds.

FLEXIBILITY

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

In this Financing Order, we approve the financing of DEC's Storm Recovery Costs and Up-front Financing Costs through Storm Recovery Bonds with terms to be established by DEC, at the time of pricing, subject to compliance with the IAL procedures outlined in this Financing Order. As discussed above, in the Evidence and Conclusions for Finding of Fact No. 34, DEC provided testimony establishing that the proposed issuance of Storm Recovery Bonds by DEC and the imposition and collection of the Storm Recovery Charge from DEC's retail customers are expected to provided quantifiable benefits to such customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds.

N.C. Gen. Stat. § 62-172(b)(3)b.8. requires this Commission to specify the degree of flexibility to be afforded to DEC in establishing the terms and conditions of the Storm Recovery Bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs consistent with N.C. Gen. Stat. § 62-172(b)(3)b.1.-7.

DEC proposed that its SPE issue Storm Recovery Bonds with a scheduled final payment date of no more than 15 years from the date of the issuance of the Storm Recovery Bonds and that the legal maturity date may be longer in accordance with rating agency requirements. Pursuant to witness Atkins' testimony, this difference provides additional

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credit protection, allowing shortfalls in principal payments to be recovered over an additional time period and therefore helping in achieving the targeted AAA or equivalent ratings. The Commission finds that the recovery period proposed by DEC to recover the Storm Recovery Charges is appropriate.

We find that Storm Recovery Bonds should be issued in one or more series, each series of Storm Recovery Bonds should be issued in one or more tranches, and the Storm Recovery Bonds should be structured by DEC to achieve the Statutory Cost Objectives. Further, the Storm Recovery Bonds shall be structured such that the expected payment of the principal of and interest on the Storm Recovery Bonds is expected to be substantially level on an annual basis over those expected terms.

Subject to the IAL procedures, DEC shall be afforded flexibility in determining the final terms of the Storm Recovery Bonds, including payment and maturity dates, interest rates (or the method of determining interest rates), the terms of any interest rate swap agreement, interest rate lock or similar agreement, the creation and funding of any supplemental capital, reserve or other subaccount, and the issuance of Storm Recovery Bonds through either one SPE or multiple SPEs, except as otherwise provided in this Financing Order.

As noted above, certain costs, such as debt service on the Storm Recovery Bonds, as well as the on-going fees of the trustee, rating agency surveillance fees, regulatory assessment fees and the On-going Financing Costs of any other credit enhancement or interest rate swaps, will not be known until after the pricing of a series of Storm Recovery Bonds. This Financing Order provides flexibility to recover such costs through the Storm Recovery Charge and the true-up of such charge. At the same time, we have established

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the IAL procedures of this Financing Order which are intended to ensure that the structuring and pricing of Storm Recovery Bonds achieves the Statutory Cost Objectives.

The Commission finds that a bond structure, providing for substantially levelized annual revenue requirements over the expected life of the Storm Recovery Bonds, is in the general public interest and should be used. This structure offers the benefit of not relying upon public utility customer growth and will allow the resulting overall weighted average Storm Recovery Charges to remain level or decline over time, if billing determinants remain level or grow.

CONCLUSION

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

Based on the statutory criteria and procedures, the record in this proceeding, and other provisions of this Financing Order, the statutory requirements for issuance of a financing order have been met, specifically that the issuance of the Storm Recovery Bonds and the imposition and collecting of Storm Recovery Charges authorized by this Financing Order are expected to provide quantifiable benefits to customers of DEC as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds and that the structuring and pricing of the Storm Recovery Bonds issued on behalf of DEC are reasonably expected to result in the lowest Storm Recovery Charges payable by the customers of DEC consistent with market conditions at the time such Storm Recovery Bonds are priced and the terms set forth in this Financing Order.

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IT IS, THEREFORE, SO ORDERED, as follows:

Approvals

1. **Approval of Application.** DEC's Joint Petition for the issuance of a financing order pursuant to the Securitization Statute is approved, as provided in this Financing Order.

2. **Authority to Securitize**. DEC's Joint Petition for Financing Orders authorizing the issuances by DEC and DEP of storm recovery bonds in one or more series is granted, subject to the terms set forth in the body of this Financing Order and the related financing order for DEP. DEC is hereby authorized to issue Storm Recovery Bonds secured by the pledge of Storm Recovery Property, in one or more series in an aggregate principal amount not to exceed the Securitizable Balance (as of the date the first series of Storm Recovery Bonds are issued). The proceeds are to be used to finance the equivalent of (i) recovery of Storm Recovery Costs, which includes Carrying Costs necessary to account for the number of days, as applicable, either greater than or less than assumed in the carrying costs calculation, calculated at the Company's approved weighted average cost of capital plus (ii) recovery of the Up-front Financing Costs incurred in connection with issuance of the Storm Recovery Bonds. Carrying Costs and Up-front Financing Costs are subject to update, adjustment and approval pursuant to the terms of this Financing Order and the IAL procedures as provided by this Financing Order.

3. **Approval of Regulatory Asset.** DEC's request to establish a regulatory asset to defer any prudently incurred excess amounts of Up-front Financing Costs is approved.

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4. **Recovery of Storm Recovery Charges.** DEC shall impose on, and shall collect, as initial servicer, from all existing and future customers receiving transmission or distribution service, or both, from DEC, even if such customer elects to purchase electricity from an alternative supplier, as provided in this Financing Order, Storm Recovery Charges in an amount sufficient to provide for the timely recovery of its Periodic Payment Requirement detailed in this Financing Order (including, without limitation, payment of principal and interest on the Storm Recovery Bonds).

5. **Approval of Tariffs.** The form of the Tariff schedule as shown in Byrd DEC Exhibit 2 is approved.

6. **True-Up Mechanism.** The True-Up Mechanism identified in Appendix B to this Financing Order is approved and shall be applied at least semi-annually (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of a series of Storm Recovery Bonds)**.**

7. **Form Agreements.** The Commission finds good cause to authorize DEC to provide service to the SPE under the Servicing Agreement and for the Servicing Agreement to become effective following the effectiveness of the IAL. The Commission finds good cause to authorize DEC to administer the SPE under the Administration Agreement and for the Administration Agreement to become effective following the effectiveness of the IAL. The Commission finds good cause to authorize DEC to enter into a Purchase and Sale Agreement with the SPE to become effective following the effectiveness of the IAL.

8. **State Pledge.** The SPE issuing Storm Recovery Bonds is authorized, pursuant to N.C. Gen. Stat. § 62-172(k)(2) and this Financing Order, to include the State

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of North Carolina pledge, which includes a pledge by this Commission, with respect to Storm Recovery Property and Storm Recovery Bonds and related documentation as provided for in N.C. Gen. Stat. § 62-172(k)(1). The Commission finds that this State Pledge will constitute a contract with the bondholders, the owners of Storm Recovery Property, the SRB Issuer, holders of SRB Securities and other financing parties. The Commission further acknowledges that the SRB Issuer and any holder of SRB Securities would be considered financing parties for purposes of N.C. Gen. Stat. § 62-172(k).

9. **Structure.** The proposed transaction structure for the Storm Recovery Bonds, as set forth in the body of this Financing Order is approved.

10. **Mitigation of Rate Impacts.** DEC's comparison between the net present value of the costs to customers that are estimated to result from Storm Recovery Bonds and the costs that would result from the application of the traditional method of financing and recovering Storm Recovery Costs from customers satisfies the terms of the DEC Settlement.

Reports and Accounting

11. **Issuance Advice Letter.** DEC shall file a combined IAL/TUAL in final form with the Commission within one business day after actual pricing, substantially in the form of Appendix C to this Financing Order describing the final structure and terms of the Storm Recovery Bond issuance, including an updated accounting of the Up-front Financing Costs and the final Carrying Costs. Finally, the combined IAL/TUAL shall include certifications from DEC if required, that the structuring, pricing and Financing Costs of the Storm Recovery Bonds achieved the Statutory Cost Objectives. Unless the Commission issues an order stopping the Storm Recovery Bond issuance before noon on the third

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business day after pricing because the Commission determines that the IAL/TUAL and all required certifications have not been delivered or the transaction does not comply with the Standards of this Financing Order, the transaction proceeds without any further action of this Commission. The Commission shall only issue an order to stop the transaction if the Commission determines that (a) the transaction does not comply with the Standards of this Financing Order, or (b) DEC has not delivered the required certification in a form acceptable to the Commission.

Prior to the filing of the IAL/TUAL and through the period ending with the issuance of the Storm Recovery Bonds, DEC will, to extent requested by this Commission, provide this Commission or its Designated Member with timely information so that the Commission acting for itself or through its Designated Member can participate fully and in advance regarding all material aspects relating to the structuring and pricing of, and Financing Costs relating to the Storm Recovery Bonds.

12. **True-Up Adjustment Letter.** DEC or its assignee(s) are authorized to recover the Periodic Payment Requirement and shall file with the Commission at least semi-annually (and at least quarterly beginning 12 months prior to the last scheduled payment date of the latest maturing tranche of Storm Recovery Bonds) a TUAL as described in this Financing Order and shall be based upon the cumulative differences, regardless of the reason, between the Periodic Payment Requirement and the actual amount of Storm Recovery Charge remittances to the indenture trustee for the series of Storm Recovery Bonds. Upon the filing of a TUAL made pursuant to this Financing Order, the Commission shall either administratively approve the requested true-up calculation in writing or inform the servicer of any mathematical or clerical errors in its calculation as

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expeditiously as possible but no later than 30 days following the servicer's true-up filing. Notification and correction of any mathematical or clerical errors shall be made so that the true-up is implemented within 30 days of the servicer's filing of a TUAL and no potential modification to correct an error in a TUAL shall delay its effective date and any correction or modification which could not be made prior to the effective date shall be made in the next TUAL. Upon administrative approval or the passage of 30 days without notification of a mathematical or clerical error, no further action of this Commission will be required prior to implementation of the true-up.

13. **Changes to Storm Recovery Charges.** Upon any change to customer rates and charges stemming from the True-Up Mechanism, DEC shall file appropriately-revised tariff sheets with this Commission, provided, however, that approval of the Storm Recovery Charges shall not be delayed or otherwise adversely impacted by the Commission's decision with respect to the tariff.

14. **Special Purpose Trust.** In the alternative to directly issuing and marketing the Storm Recovery Bonds to unaffiliated investors through either a registered public offering or unregistered exempt offering, the Storm Recovery Bonds may be sold to a single special purpose trust established by Duke Energy Corporation, parent of DEC as described in the Discussion and Conclusions.

15. **Imposition and Collection, Nonbypassability.** DEC is authorized to impose, bill, charge, collect, receive, and adjust from time to time pursuant to the True-Up Mechanism (as described in this Order) a Storm Recovery Charge, to be collected on a per kWh basis from each of its existing and future retail customers until the related Storm Recovery Bonds are paid in full and all related Financing Costs and other costs of the bonds

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have been recovered in full. Such Storm Recovery Charges shall be nonbypassable charges that are separate and apart from DEC's base rates and shall be paid by all DEC jurisdictional existing and future customers receiving transmission or distribution service, or both, from DEC or its successors or assignees under Commission-approved rate schedules as provided in this Financing Order. Such Storm Recovery Charges shall be in amounts sufficient to ensure the timely recovery of DEC's Storm Recovery Costs and Financing Costs (Up-front and On-going) detailed in this Financing Order and the IAL (including payment of principal of and interest on the Storm Recovery Bonds).

16. **Allocation.** The Storm Recovery Charges shall be allocated to the customer rate classes in accordance with the description included in witness Abernathy's testimony, in the manner in which these costs or its equivalent were allocated in the cost-of-service study filed by the Company and approved on ___ in the DEC Rate Order, until altered by a subsequent rate case order.

17. **Collection Period.** This Financing Order and the Storm Recovery Charges authorized hereby shall remain in effect until the Storm Recovery Bonds and all Financing Costs (including tax liabilities) related thereto have been paid or recovered in full. This Financing Order shall remain in effect and unabated notwithstanding the reorganization, bankruptcy, or other insolvency proceedings of DEC or its successors or assignees.

18. Following repayment of Storm Recovery Bonds and the relevant Financing Costs authorized in this Financing Order and release of the funds by the indenture trustee, each SPE shall distribute the final balance of its Collection Account to DEC and DEC shall credit other electric rates and charges by a like amount, less the amount of the relevant

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Capital Subaccount and any unpaid return on invested capital due to DEC as set forth in the body of this Financing Order.

19. **Ownership Notification and Separate Line Item Charge**. The electric bills of DEC must explicitly reflect that a portion of the charges on such bill represents Storm Recovery Charges approved in this Financing Order and must include a statement to the effect that the SPE is the owner of the rights to Storm Recovery Charges and that DEC is acting as servicer for the SPE. The tariff applicable to customers must indicate the Storm Recovery Charge and the ownership of that charge. DEC shall identify amounts owed with respect to its Storm Recovery Property as a separate line item on individual electric bills.

Storm Recovery Property

20. **Outside Costs.** Costs associated with the Commission or Public Staff's outside consultant and outside counsel, to the extent such costs are eligible for compensation and approved for payment under the terms of such party's contractual arrangements with the Commission or Public Staff, as such arrangements may be modified by any amendment entered into at the Commission or Public Staff's sole discretion, will qualify as Up-front Financing Costs and be paid from proceeds of Storm Recovery Bonds.

21. **Creation of Storm Recovery Property.** The creation of the DEC's Storm Recovery Property as described in this Financing Order is approved and, upon transfer of the Storm Recovery Property to the SPE, shall be created, and shall consist of: (1) all rights and interests of DEC or its successors or assignees under this Financing Order, including the right to impose, bill, charge, collect, and receive Storm Recovery Charges authorized in this Financing Order and to obtain periodic adjustments to such charges as provided in

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this Financing Order, and (2) all revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in this Financing Order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, charged, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds. The creation of Storm Recovery Property is conditioned upon, and shall be simultaneous with, the sale or other transfer of the Storm Recovery Property to the SPE, the issuance of the Storm Recovery Bonds and the pledge of the Storm Recovery Property to secure a series of Storm Recovery Bonds.

22. **Irrevocability.** Upon the earlier of either (i) the transfer of the Storm Recovery Property or (ii) issuance of the Storm Recovery Bonds, this Financing Order is irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this Financing Order, the Commission may not amend, modify, or terminate this Financing Order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust the Storm Recovery Charges approved in this Financing Order.

Structure of Securitization

23. **SPE.** DEC is authorized to form one or more SPEs to be structured as discussed in this Financing Order. DEC is authorized to execute one or more LLC Agreements, consistent with the form included as Heath Exhibit 2e to witness Heath's testimony and the terms and conditions of this Financing Order. The SPE shall be funded with an amount of capital that is sufficient for the SPE to carry out its intended functions as contemplated in the Joint Petition and this Financing Order. The Commission approves an initial capital contribution of 0.5 percent of the initial aggregate principal amount of a

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series of Storm Recovery Bonds. The capital contributions by DEC to the SPE shall be funded by DEC and not from the proceeds of the sale of Storm Recovery Bonds. DEC will be permitted to earn a rate of return on its invested capital in its SPE equal to the rate of interest payable on the longest maturing tranche of Storm Recovery Bonds and this return on invested capital should be a component of the Periodic Payment Requirement.

24. **Servicing and Administration Fees.** The servicing and administration fees collected by DEC or any affiliate of DEC, acting as either the servicer or the administrator under the Servicing Agreement or Administration Agreement, respectively, will be included in DEC's cost of service such that DEC will credit back all periodic servicing fees in excess of DEC's or an affiliate of DEC's incremental costs of performing servicing as administration functions. The expenses incurred by DEC, or such affiliate to perform obligations under the Servicing Agreement or Administration Agreement not otherwise recovered through the Storm Recovery Charges will likewise be included in DEC's cost of service.

25. **DEC as Servicer.** DEC shall act as initial servicer under the proposed financing transaction, and is granted flexibility to act as initial servicer pursuant to the Servicing Agreement discussed in this Financing Order.

26. **Third Party Supplier.** If the State of North Carolina or this Commission decides to allow billing, collection and remittance of the Storm Recovery Charges by a third party supplier within the DEC service territory, such authorization will be consistent with the rating agencies' requirements necessary for the Storm Recovery Bonds and SRB Securities to receive and maintain the targeted triple-A rating as described in Findings of Fact No. 17.

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27. **Issuance.** In accordance with the terms of this Financing Order and subject to the criteria and procedures described herein, the SPE is authorized to issue Storm Recovery Bonds in an aggregate principal amount not to exceed the Securitizable Balance (as of the date the Storm Recovery Bonds are issued) and may pledge to an indenture trustee, as collateral for payment of the Storm Recovery Bonds, the Storm Recovery Property, including the SPE's right to receive the related Storm Recovery Charges as and when collected, the SPE's rights under the Servicing Agreement and other collateral described in the Indenture. As provided in N.C. Gen. Stat. § 62-172(c)(2)., DEC retains sole discretion regarding whether to assign, sell, or otherwise transfer Storm Recovery Property or to cause the Storm Recovery Bonds to be issued, including the right to defer or postpone such assignment, sale, transfer or issuance and this Commission will not refuse to allow DEC to recover Storm Recovery Costs in an otherwise permissible fashion.

28. **IRS Safe Harbor Provisions.** DEC shall be responsible to structure the Storm Recovery Bond transactions in a way that complies with the "safe harbor" provisions of IRS Revenue Procedure 2005-62.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of _____, 2021.

NORTH CAROLINA UTILITIES COMMISSION

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APPENDIX A

SUMMARY OF CALCULATION OF DEC'S SECURITIZABLE BALANCE

Estimated Storm Recovery Costs (incremental O&M costs and capital investments)	$ 188,374,000
Estimated Carrying Costs through bond issuance date[1]	$ 37,196,000
Estimated Up-front Financing Costs[2]	$ 5,230,000
Estimated Principal Amount of Storm Recovery Bonds	$ 230,800,000

[1] Assuming the Storm Recovery Bonds are issued on approximately June 1, 2021.
[2] Final Up-front Financing Costs to be included in the Issuance Advice Letter.

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APPENDIX B

[Form of Standard True-Up Adjustment Letter]

[, 20]

VIA ELECTRONIC FILING

Ms. Kimberly A. Campbell
Office of the Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4335

Re: Duke Energy Carolinas, LLC's True-Up Adjustment Letter
Docket No. E-7, Sub 1243

Dear Clerk Campbell:

Pursuant to the North Carolina Utilities Commission's ("Commission") [, 20] Order in Docket No. E-7, Sub 1243 (the "DEC Financing Order"), Duke Energy Carolinas, LLC ("DEC") as Servicer of the [ ] ("Storm Recovery Bonds") has filed a request for an adjustment to the storm recovery bond charges ("Storm Recovery Charges"). This adjustment is intended to satisfy the requirements of N.C. Gen. Stat. § 62-172(b)(3)d., and the Financing Order by ensuring that the Storm Recovery Charges will recover amounts sufficient to timely provide for payments of debt service and other required amounts in connection with the Storm Recovery Bonds.

Per the Financing Order, "After issuance of Storm Recovery Bonds on behalf of DEC, the servicer will submit at least semi-annually (and at least quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of…Storm Recovery Bonds) a letter in this docket for Commission review, as described in N.C. Gen. Stat. § 62-172(b)(3)d., and in the form attached hereto…and as an exhibit to the Servicing Agreement" ("True-up Adjustment Letter" or, "TUAL"). The Storm Recovery Bonds were issued on [, 20]. DEC filed its first True-Up Adjustment Letter on [, 20].

Ordering Paragraph 11 of the Financing Order describes how such True-Up Adjustment Letters are to be handled.

> Upon the filing of a TUAL made pursuant to this Financing Order, Commission Staff shall either administratively approve the requested true-up calculation in writing or inform the servicer of any mathematical or clerical errors in its calculation as expeditiously as possible but no later than 30 days following the

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servicer's true-up filing. Notification and correction of any mathematical or clerical errors shall be made so that the true-up is implemented within 30 days of the servicer's filing of a TUAL and no potential modification to correct an error in a TUAL shall delay its effective date and any correction or modification which could not be made prior to the effective date shall be made in the next TUAL. Upon administrative approval or the passage of 30 days without notification of a mathematical or clerical error, no further action of this Commission will be required prior to implementation of the true-up.

Attached is the [TBD] Revised Sheet No. [ ] reflecting the change in the Storm Recovery Charge.

Per DEC's request in its True-Up Adjustment Letter and in accordance with the Financing Order, the proposed adjustments to the Storm Recovery Charges will be effective on [, 20].

Respectfully submitted,

Duke Energy Carolinas, LLC

Attachments

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APPENDIX B

DUKE ENERGY CAROLINAS, LLC
Storm Recovery Charge True-Up Mechanism Form For the Period , 20 through 20,

	Description		Calculation of the True-up (1)		Projected Revenue Requirement to be Billed and Collected (2)		Revenue Requirement for Projected Two Remittance Periods (1)+(2)=(3)
1	**Storm Recovery Bond Repayment Charge (remitted to SPE)**						
2	True-up for the Prior Remittance Period Beginning and Ending:						
3	Prior Remittance Period Revenue Requirements						
4	Prior Remittance Period Actual Cash Receipt Transfers Interest income:						
5	Cash Receipts Transferred to the SPE						
6	Interest income on Subaccounts at the SPE						
7	Total Current Period Actual Daily Cash Receipts Transfers and Interest Income (Line 5 + 6)						
8	(Over)/Under Collections of Prior Remittance Period Requirements (Line 3+7)						
9	Cash in Excess Funds Subaccount						
10	Cumulative (Over)/Under Collections through Prior Remittance Period (Line 9+10)		$				$
11	Current Remittance Period Beginning _____ and Ending _____						
12	Principal						
13	Interest						
14	Servicing Costs						
15	Other On-Going Costs						
16	Total Current Remittance Period Revenue Requirement (Line		$				

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	2+3+4+5)						
17	Current Remittance Period Cash Receipt Transfers and Interest Income:						
18	Cash Receipts Transferred to SPE	(A)		(B)			
19	Interest Income on Subaccounts at SPE	(A)		(B)			
20	Total Current Remittance Period Cash Receipt Transfers and Interest Income (Line 18+19)		$		$		
21	Estimated Current Remittance Period (Over)/Under Collection (Line 19+24)		$		$		$
22	Projected Remittance Period Beginning _____and Ending _____						
23	Principal						
24	Interest						
25	Servicing Costs						
26	Other On-Going Financing Costs						
27	Projected Two Remittance Periods Revenue Requirement (Line 23+24+25+26)				$		$
28	Total Revenue Requirements to be Billed During Projected Two Remittance Periods (Line 10+21+27)						$
29	Forecasted KWh Sales for the Projected Two Remittance Periods (adjusted for uncollectibles)						
30	Average Retail Storm Recovery Charge per kWh (Line 28/29)					(C)	
31	Notes:						
32	(A) Amounts are based on a billed and collected basis.						
33	(B) Includes estimated amounts for through .						
34	(C) Allocation of this amount to each rate class is addressed by witness Jonathan Byrd in his testimony.						

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APPENDIX C

[Form of Issuance Advice Letter]

[, 20]

VIA ELECTRONIC FILING

Ms. Kimberly A. Campbell
Office of the Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4335

Re: Duke Energy Carolinas, LLC's Issuance Advice Letter
Docket No. E-7, Sub 1243

Dear Clerk Campbell:

Pursuant to the financing order in the above-captioned docket ("Financing Order"), Duke Energy Carolinas, LLC (the "Company") hereby transmits for filing this combined Issuance Advice Letter and Form of True-Up Adjustment Letter. Any terms not defined herein shall have the meanings ascribed thereto in the Financing Order or N.C. Gen. Stat. § 62-172.

In the Financing Order, the Commission requires the Company to file an Issuance Advice Letter following pricing of a series of Storm Recovery Bonds.

The terms of pricing and issuance of the first series of Storm Recovery Bonds are as follows:

Name of Storm Recovery Bonds: [ ]
Name of SPE: [ ]
Name of Storm Recovery Bond Trustee:
Name of SRB Securities: [SRB Notes]
Name of SRB Issuer: [ ]
Name of SRB Trustee: [ ]
Expected Closing Date: [ ]
Preliminary Bond Ratings[1]: Moody's, [Aaa(sf)]; Standard & Poor's, [AAA(sf)]; Fitch, [AAAsf] (final ratings to be received prior to closing)
Total Principal Amount of Storm Recovery Bonds to be Issued (i.e., Amount of Storm Recovery Costs and Up-Front Financing Costs to be Financed): $[ ] (See Attachment 1)
Estimated Up-Front Financing Costs: $[ ] (See Attachment 2)
Interest Rates and Expected Amortization Schedules of the Storm Recovery Bonds and

[1] The Company anticipates receiving bond ratings from at least two of the three major rating agencies.

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SRB Notes (See Attachment 3):
Distributions to Investors: Semi-annually
Weighted Average Coupon Rate[2]: [ ]%
Annualized Weighted Average Yield[3]: [ ]%
Initial Balance of Capital Subaccount: $[ ]
Estimated/Actual On-going Financing Costs for first year of Storm Recovery Bonds: $[ ] (See Attachment 4)

The Financing Order requires the Company to confirm, using the methodology approved therein, that the actual terms of the SRB Notes and Storm Recovery Bonds result in compliance with the standards set forth in the Financing Order. These standards are:

1. the issuance of Storm Recovery Bonds and imposition and collection of Storm Recovery Charges as authorized in this Financing Order provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds;

2. the aggregate principal amount of Storm Recovery Bonds issued does not exceed the Securitizable Balance;

3. the SRB Notes and Storm Recovery Bonds will be issued in one or more series comprised of one or more tranches having target final payment of 15 years;

4. the SRB Notes have received a rating of Aaa(sf) / AAA(sf) from at least two of the three major rating agencies;

5. the SRB Notes and Storm Recovery Bonds are structured to achieve substantially level debt service payments on an annual basis;

6. the issuance of the SRB Notes and Storm Recovery Bonds has been structured in accordance with IRS Rev. Proc. 2005-62; and

7. the structuring and pricing of the Storm Recovery Bonds, including the issuance of SRB Notes, resulted in the lowest Storm Recovery Charges consistent with market conditions at the time the Storm Recovery Bonds are priced and the terms set forth in this Financing Order.

The initial storm recovery charge (the "Initial Charge") has been calculated in accordance with the methodology described in the Financing Order and based upon the structuring and pricing terms of the Storm Recovery Bonds set forth in this combined Issuance Advice Letter and Form of True-Up Adjustment Letter.

Attachment 5 provides the Revenue Requirements for calculating the Initial Charge. Attachment 6 calculates the Initial Charge based upon the cost allocation formula approved in the Financing

[2] Weighted by modified duration and principal amount of each tranche.
[3] Weighted by modified duration and principal amount, calculated including selling commissions.

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Order. Attachment 7 is a comparison between the net present value of costs to customers that are estimated to result from the issuance of Storm Recovery Bonds and the costs that would result from the application of the traditional method of recovering Storm Recovery Costs from customers. Also attached are the calculations and supporting data for such tables. The Company's certification is Attachment 8.

Pursuant to the Financing Order, the transaction may proceed and the Initial Charge will take effect unless **a stop order is issued by the Commission prior to noon on [, 20](3 business days after pricing)**; and the Company, as servicer, or any successor servicer and on behalf of the trustee as assignee of the SPE, is required to apply at least semi-annually for mandatory periodic adjustment to the Storm Recovery Charges. The Initial Charge shall remain in effect until changed in accordance with the provisions of Ordering Paragraph [12] of the Financing Order.

The Company's certification required by the Financing Order is set forth in Attachment 8, which also includes the statement of the actions taken by the Company to achieve the Statutory Objectives as required by the Financing Order.

Respectfully submitted,

Duke Energy Carolinas, LLC

Attachments

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Attachment 1

TOTAL PRINCIPAL AMOUNT OF STORM RECOVERY BONDS TO BE ISSUED (TOTAL AMOUNT OF STORM RECOVERY COSTS AND UP- FRONT FINANCING COSTS TO BE FINANCED)

Storm Recovery Costs, including carrying costs through [date of the Rate Order]	$
Carrying costs subsequent to [the date of the Rate Order] to bond issuance date	
Estimated Up-front Financing Costs included in Proposed Structure (refer to attachment 2)	$
Total Storm Recovery Bond Issuance (rounded up)	**$**

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Attachment 2

ESTIMATED UP-FRONT FINANCING COSTS

Underwriters' Fees and Expenses	$
Servicer Set-up Fee (including IT Programming Costs)	$
Legal Fees	$
Rating Agency Fees	$
Public Staff Financial Advisor Fees	$
Public Staff Legal Fees	$
DEC Structuring Advisor Fee	$
Accounting Fees	$
SEC Fees	$
SPE Set-up Fee	$
SRB Trust Set-up Fee allocable to DEC	$
Marketing and Miscellaneous Fees and Expenses	$
Printing / Edgarizing Expenses	$
Trustees/Trustees Counsels Fee and Expenses	$
Original Issue Discount	$
Other Ancillary Agreements	$
TOTAL ESTIMATED UP-FRONT FINANCING COSTS	$

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Attachment 3

EXPECTED AMORTIZATION SCHEDULE

A. General Terms

Tranche	Price	Coupon	Fixed/ Floating	Average Life	Expected Final Maturity	Legal Final Maturity

B. Scheduled Amortization Requirement of SRB Notes

Series [ ], Tranche [A-1]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

Series [ ], Tranche [A-2]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

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Series [ ], Tranche [A-3]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

Series [ ], Tranche [A-4]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

Series [ ], Tranche [A-5]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

C. Scheduled Amortization Requirement of Storm Recovery Bonds

Series [ ], Tranche [A-1]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

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Series [ ], Tranche [A-2]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

Series [ ], Tranche [A-3]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

Series [ ], Tranche [A-4]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

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Series [ ], Tranche [A-5]					
Payment Date	Beginning Principal Balance	Interest	Principal	Total Payment	Ending Principal Balance

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Attachment 4

ESTIMATED ANNUAL ON-GOING FINANCING COSTS

	Annual Amount
Servicing Fee[1]	$
Return on Invested Capital	$
Administration Fee	$
Accounting Fees	$
Regulatory Assessment Fees	$
Legal Fees	$
Rating Agency Surveillance Fees	$
Trustee Fees	$
SRB Trustee Fees Allocable to DEC	$
Independent Manager Fees	$
Miscellaneous Fees and Expenses	$
TOTAL ESTIMATED ANNUAL ON-GOING FINANCING COSTS	$

[1] Low end of the range assumes the Company is the servicer (0.05%). Upper end of the range reflects an alternative servicer (0.60%).

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Attachment 5

REVENUE REQUIREMENT AND INPUT VALUES

Initial Payment Period from [, 20]to [, 20]	**Bond Repayment**	**Total**
Forecasted retail kWh sales		
Percent of billed amounts expected to be charged-off		%
Forecasted % of billings paid in the applicable period		%
Forecasted retail kWh sales billed and collected		
Storm Recovery Bond principal payment	$	$
Storm Recovery Bond interest payment	$	$
Forecasted On-going Financing Costs (excluding principal and interest)	$	$
Total collection requirement for applicable period	$	$

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Attachment 6

Rate Class	Applicable Schedules	(A) Revenue Requirement Allocated by Class[1] ($'000)	(B) Effective Sales[2] (MWh)	(C) Storm Recovery Charge (¢/kWh) (A) * 100 / (B)
Residential	ES, RE, RE-CPP, RE-TOU-CPP, RE-TOUD-DPP, RS, RS-CPP, RS-TOU-CPP, RS-TOUD-DPP, RT	$12,563	22,221,707	0.0565
General Service	BC, HP, LGS, OPT-E, OPT-V, PG, S, SGS, SGS-CPP, SGS-TOU-CPP, SGS-TOUD-DPP, TS	$3,598	22,921,898	0.0157
Industrial	HP, I, OPT-E, OPT-V, PG	$1,015	12,257,066	0.0083
Lighting	NL, OL, PL	$897	665,536	0.1348
Total		$18,073	58,066,207	0.0311

[1] Abernathy Exhibit 3 - Allocation of Storm Recovery Charge to Customer Classes as filed in Docket No. E-7, Sub 1243. Revenue Requirements were grossed-up to reflect uncollectible account write-offs and regulatory fees.

[2] Effective Sales are based on the Company's 2020 IRP retail load forecast for year 2021. Effective Sales have been allocated to Rate Classes using billed kWh sales for year 2018.

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Attachment 7

Quantifiable Benefits to Customers

[To be updated]

[Workpapers to be attached]

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Attachment 8

Form of Company Certification

[, 20]

Ms. Kimberly A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27603-5918

Re: Duke Energy Carolinas, LLC's Company Certification
Docket No. E-7, Sub 1243

Dear Clerk Campbell,

Duke Energy Carolinas, LLC (the "Company") submits this Certification pursuant to Ordering Paragraphs [10 and 11] of the Financing Order in Docket No. E-7, Sub 1243 (the "Financing Order"). All capitalized terms not defined in this letter shall have the meanings ascribed to them in the Financing Order.

In its issuance advice letter dated [, 20], the Company has set forth the following particulars of the Storm Recovery Bonds:

Name of Storm Recovery Bonds:
Name of SPE: [ ]
Name of Storm Recovery Bond Trustee:
Name of SRB Issuer: [ ]
Name of SRB Securities: [SRB Notes]
Name of SRB Trustee: [ ]
Closing Date: [, 20]
Preliminary Bond Ratings[4]: Moody's [Aaa(sf)]; Standard & Poor's [AAA(sf)]; Fitch [AAAsf] (final ratings to be received prior to closing)
Total Principal Amount of Storm Recovery Bonds to be Issued: $ (See Attachment 1)
Estimated Up-front Financing Costs: $ (See Attachment 2)
Interest Rates and Expected Amortization Schedule: (See Attachment 3)
Distributions to Investors: Semi-annually

[4] The Company anticipates receiving bond ratings from at least two of the three major rating agencies.

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Weighted Average Coupon Rate[5]: %
Annualized Weighted Average Yield[6]: %
Initial Balance of Capital Subaccount: $
Estimated/Actual On-going Financing Costs for first year of Storm Recovery Bonds: $[ ]

As required by the Financing Order, the Company prepared a comparison between the net present value of costs to customers that are estimated to result from the issuance of Storm Recovery Bonds and the costs that would result from the application of the traditional method of recovering storm recovery costs from customers.

In accordance with the procedures set forth in the Financing Order, the following actions were taken in connection with the structuring and pricing and financing costs of the Storm Recovery Bonds in order to satisfy the statutory cost objectives:

- [Included credit enhancements in the form of the true-up mechanism and an equity contribution to [ ] of 0.50% of the original principal amount of the bonds;
- Structured the financing so that the SRB Notes would not be asset backed securities within the meaning of Item 1101(c) of Regulation AB;
- Sold the Storm Recovery Bonds to [ ], a Delaware grantor trust, which offered SRB Notes secured by the Storm Recovery Bonds and storm recovery bonds issued by DEP;
- Ensured the Registration Statement contained proper disclosures to communicate the superior credit features of the SRB Notes, which are secured by the Storm Recovery Bonds;
- Developed rating agency presentations and worked actively with the rating agencies during the rating agency process to achieve Aaa(sf) / AAAsf from at least two of the three major rating agencies;
- Worked to select key transaction participants, including lead underwriters and co-managers through an RFI process to determine that they have relevant experience and execution capabilities, and who were aligned with DEC's objectives, namely broad distribution to investors and willingness to market the bonds in a manner consistent with the superior credit quality and uniqueness of the bonds;
- Hired a diverse group of underwriters, including underwriters with international and mid-tier expertise in order to attract a wide variety of potential investors;
- Reviewed detailed marketing plans submitted by each lead underwriter;
- Developed all bond transaction documents, marketing materials and legal opinions in a plain English manner while balancing SEC disclosure requirements, in an effort to

[5] Weighted by modified duration and principal amount of each tranche.
[6] Weighted by modified duration and principal amount, calculated including selling commissions.

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ensure investors could more easily understand the high-quality nature of the bond offering;

- Allowed sufficient time for investors to review [relevant marketing materials] and preliminary prospectus and to ask questions regarding the transaction;
- Attended telephonic pre-marketing investor meetings throughout 2021;
- Arranged issuance of rating agency pre-sale reports during the marketing period;
- During the period that the bonds were marketed, held numerous market update discussions with the underwriting team, [and the Commission or its Designated Member] to develop recommendation for pricing;
- Had multiple conversations with all of the members of the underwriting team during the marketing phase in which we stressed the requirements of the Financing Order;
- Developed and implemented a marketing plan designed to encourage each of the underwriters to aggressively market the bonds to a broad base of prospective corporate and asset backed securities investors, including investors who have not previously purchased this type of security;
- Conducted in person and telephonic roadshows with over [ ] investors in [ ] cities;
- Provided other potential investors with access to an internet roadshow for viewing at investors' convenience;
- Adapted the bond offering to market conditions and investor demand at the time of pricing consistent with the guidelines outlined within the Financing Order. Variables impacting the final structure of the transaction were evaluated including the length of the average lives and maturity of the bonds and the interest rate requirements at the time of pricing so that the structure of the transaction would correspond to investor preferences and rating agency requirements for the highest rating possible; and
- Developed bond allocations, underwriter compensation and preliminary price guidance designed to achieve customer savings.]

Based on the statutory criteria and procedures, the record in this proceeding, and other provisions of this Financing Order, DEC certifies the statutory requirements for issuance of a financing order and Storm Recovery Bonds have been met, specifically that the issuance of the SRB Notes and underlying Storm Recovery Bonds on behalf of DEC and the imposition and collecting of storm recovery charges authorized by this Financing Order provide quantifiable benefits to customers of DEC as compared to the costs that would have been incurred absent the issuance of Storm Recovery Bonds and that the structuring and pricing of the SRB Notes and underlying Storm Recovery Bonds issued on behalf of DEC result in the lowest storm recovery charges payable by the customers of DEC consistent with market conditions at the time such SRB Notes and underlying Storm Recovery Bonds are priced and the terms set forth in the Financing Order.

This certification is being provided to the Commission by the Company in accordance with the terms of the Financing Order, and no one other than the

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Commission shall be entitled to rely on the certification provided herein for any purpose.

Respectfully Submitted,

Duke Energy Carolinas, LLC

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Joint Petition Exhibit C:
DEP Proposed Financing Order

Docket No. E-7, Sub 1243
Docket No. E-2, Sub 1262

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Joint Petition Exhibit D:
Proposed Registration, Rating Agency, and Bond Issuance Timeline

Docket No. E-7, Sub 1243
Docket No. E-2, Sub 1262

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

Securities and Exchange Commission ("SEC") Registration and Bond Issuance Process to a June 1, 2021 Financing[1]

Date	Event	Time Period	Notes
March 8, 2021	File Registration Statement		
March 8, 2021 – April 8, 2021	SEC Review and Comments	~30 days	
April 8, 2021 – April 18, 2021	Respond to Initial SEC Comments	~10 days	Responses delivered by filing an Amendment to the Registration Statement
April 18, 2021 – May 3, 2021	SEC Review of Company Response	~15 days	Assuming the SEC takes full period to review the Amendment
May 3, 2021 – May 13, 2021	Respond to Additional SEC Comments, if Necessary	~10 days	Additional responses will be filed by additional Amendments
May 18, 2021 – May 20, 2021	Request Acceleration	~2 days	
May 20, 2021	Registration Statement Declared Effective		Registration Statement will become effective 48 hours after filing the acceleration request. The final prospectus for the offering must be filed 15 business days after the date the registration statement is declared effective.
May 24, 2021	Transaction Priced		
May 25, 2021	Issuance Advice Letter Filed	Day after pricing	DEC and DEP to file Issuance Advice Letter ("IAL") with the NCUC within one day of pricing.

[1] This is an indicative timeline that addresses the steps necessary to complete the SEC registration statement process. With regards to SEC review periods, we have assumed two rounds of SEC comments and that the SEC will take the full amount of time allotted for its review of the initial registration statement and subsequent amendments.

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May 27, 2021	Issuance Advice Letter becomes Effective	3 days after pricing	IAL becomes effective at noon on the third business day after pricing unless the NCUC issues a stop order.
June 1, 2021	Close Transactions	5 days after pricing	These transactions typically settle T+5.[2]

Rating Agency Process[3]

Date	Event	Time Period	Notes
March 29, 2021 – April 23, 2021	Prepare Rating Agency Presentation and Initial Rating Agency Review	4 weeks	The Companies and Underwriters prepare presentation materials, 17g-5 website and coordinate responses to rating agency questions.
Week of April 26	Meet with Rating Agencies	2-3 days	
April 28, 2021 – May 24, 2021	Rating Agency Follow-up	4 weeks	Responses to rating agencies' questions will be prepared by the Companies and Underwriters

[2] Adjusted due to Memorial Day which is May 31.
[3] The rating agency process is typically completed concurrently with the SEC Process.

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NCJC, et al.
Bateman Stillman Abernathy
Rebuttal Cross Exhibit 1
E-7, Sub 1276A

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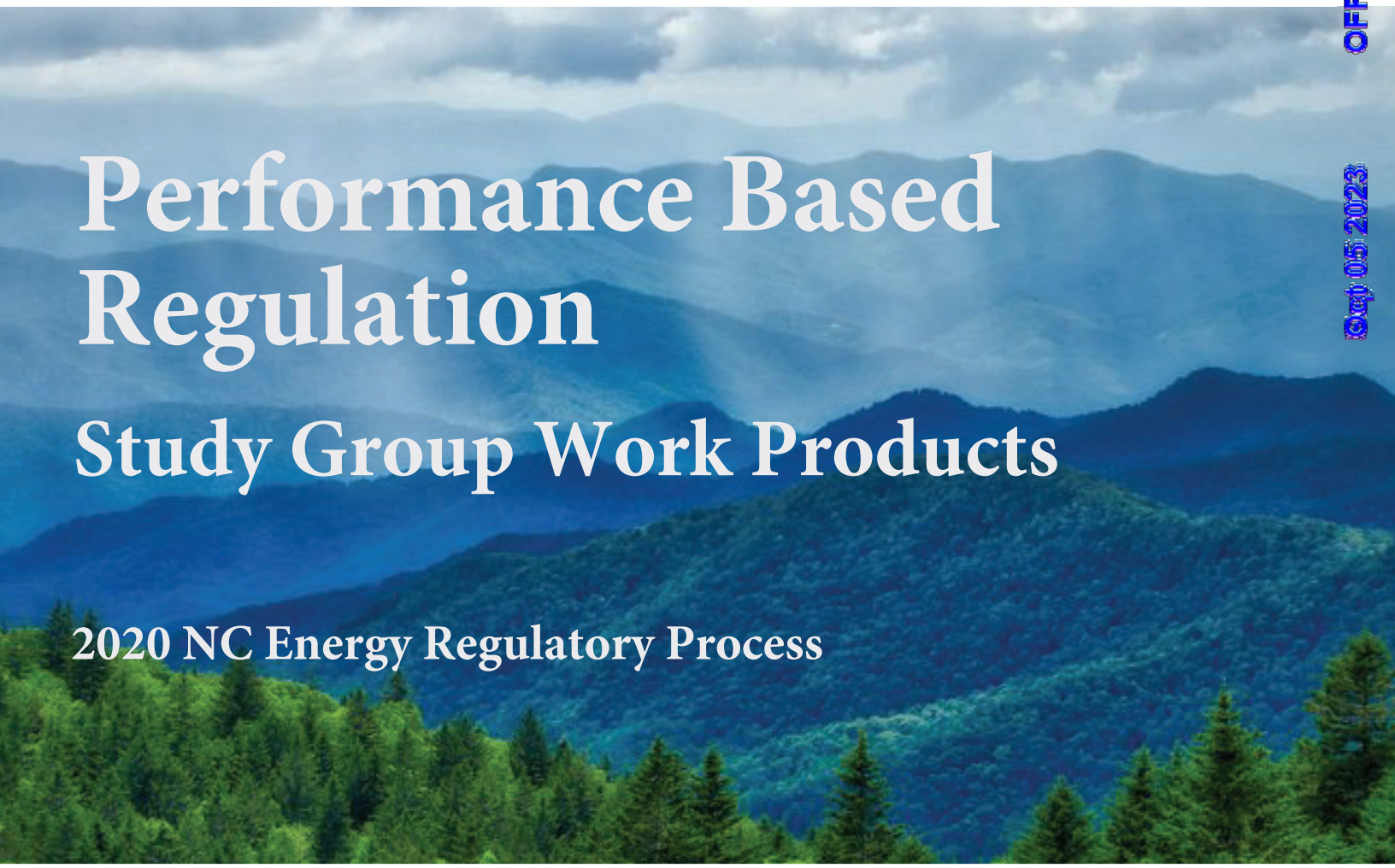


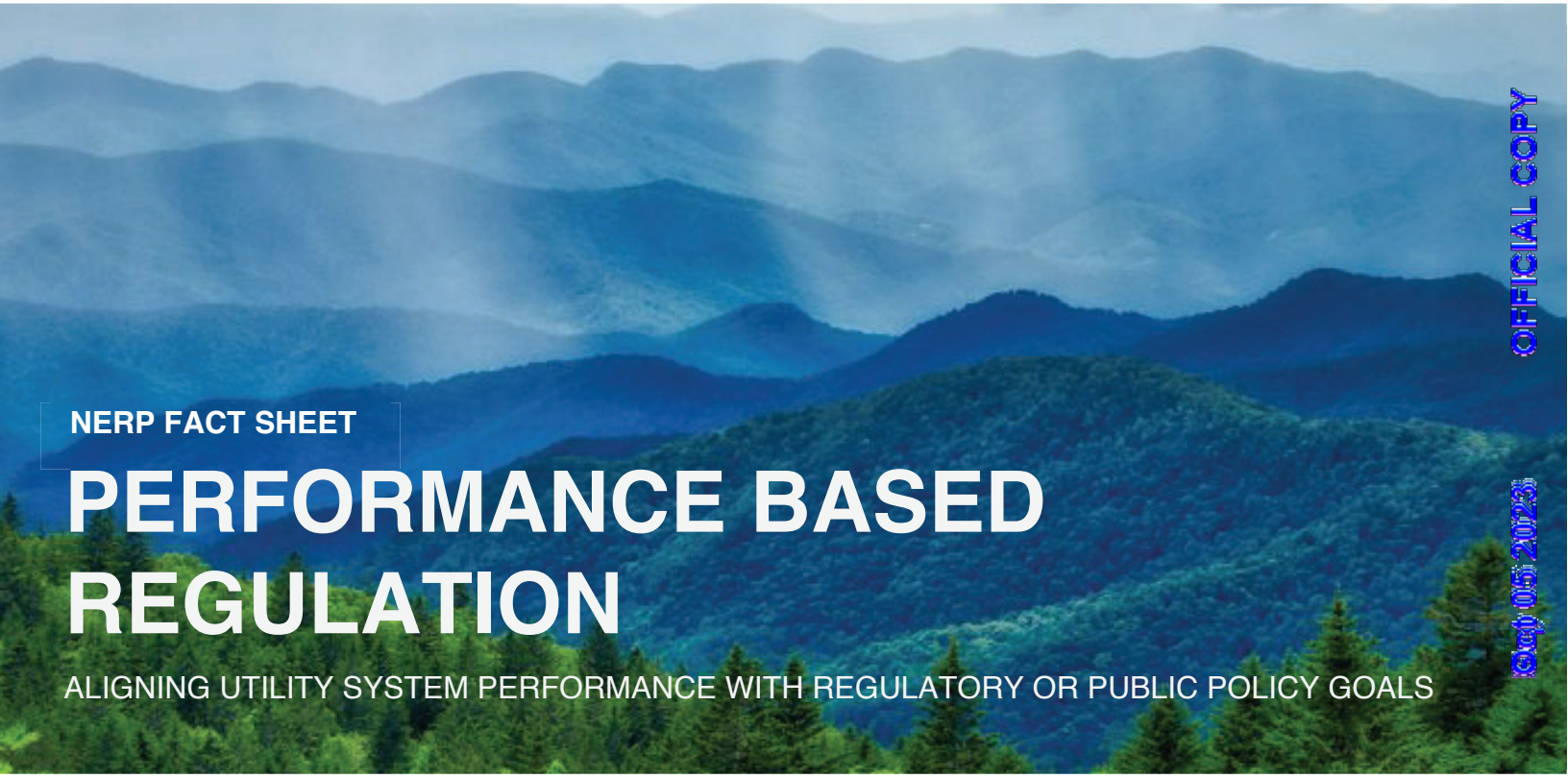
Performance Based Regulation

Study Group Work Products

2020 NC Energy Regulatory Process

Contents of this packet:

1. PBR Fact Sheet
2. PBR Regulatory Guidance
3. Proposed PBR Legislation
4. Case Study: Natural Gas Decoupling in North Carolina
5. Case study: Minnesota Electricity Performance Based Rates



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NERP FACT SHEET

PERFORMANCE BASED REGULATION

ALIGNING UTILITY SYSTEM PERFORMANCE WITH REGULATORY OR PUBLIC POLICY GOALS

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

WHAT IS PERFORMANCE BASED REGULATION?

Performance based regulation (PBR) is a regulatory approach that more precisely aligns utilities' profit interests with customer and societal interests through regulatory mechanisms that incentivize utilities to improve operations and management of expenses, increase program effectiveness, and otherwise align system performance with identified regulatory or public policy goals.

WHAT IS THE OPPORTUNITY?

While North Carolina is a leader in clean energy, with the second highest installed solar capacity in the nation, more than 40% of in-state generation being provided by carbon free resources, and over 110,000 clean energy sector jobs,[1] the future success of the state's clean energy transition will require, among other things, substantial greenhouse gas emission reductions; increased electric energy conservation savings over and above current savings of 1% [2]; continued grid modernization investments in storm hardening, targeted undergrounding of transmission and distribution power lines, and advanced metering; and increased integration of innovative distributed energy solutions, including customer sited solar and energy storage. Indeed, both Duke Energy and Dominion Energy have established ambitious mid-century clean energy targets. Duke's own Queue Reform Proposal calls for more than "5,390 MW of additional proposed North Carolina-sited utility-scale solar projects."[3]

Furthermore, existing utility incentives under the current ratemaking system are not always aligned with achieving these outcomes. Under the current system, utilities make more money by increasing their electric sales, which dis-incentivizes increased energy conservation. In addition, grid modernization investments are often not in a utility's financial best interest, at least in the short to medium term, as considerable time may pass between when (1) a utility first incurs financing costs to fund grid modernization investments and (2) it can stand to potentially recover all of those costs in a rate case. [4] Furthermore, a utility typically earns no profits on distributed energy, with profits being earned instead from infrastructure the utility owns and uses to provide electric services, in particular generation assets. Therefore, utilities may be incentivized to prioritize investments in utility owned generation over

[1] *See* https://www.e2.org/wp-content/uploads/2019/07/E2-Clean-Jobs-North-Carolina-2019.pdf

[2] *See* https://nicholasinstitute.duke.edu/sites/default/files/publications/North-Carolina-Energy-Efficiency-Roadmap-Final.pdf

[3] *See* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f83235af-6c15-4a08-ab04-7d03ef047383

[4] A rate case is a process through which a utility can adjust the rates it collects from customers by seeking approval from the North Carolina Utilities Commission.

investments that might, over the long term, reduce the amount of utility generation and result in cleaner energy.

If the Clean Smokestacks Act, Senate Bill 3, House Bill 589, and other landmark state clean energy legislation are any indication, further state legislative action will be crucial to the future of the state's clean energy transition. In particular, performance based regulation can help catalyze clean energy innovation.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process (NERP) has identified three mechanisms that should be adopted as a package:

1. Decoupling – a ratemaking mechanism that severs the link between utility sales and revenues by authorizing allowed revenues separate from utility sales and adjusting prices periodically to ensure actual revenues match allowed revenues.

2. Performance incentive mechanisms (PIMs) – a ratemaking mechanism that ties some portion of a utility's revenues or earnings to its performance on measurable customer, utility system, or public policy outcomes.

3. Multi-year rate plan (MYRP) with an earnings sharing mechanism – a ratemaking mechanism through which base rates and revenues are fixed for a multi-year term and a utility is barred from filing a rate case during that term (often referred to as a rate case moratorium). Rates or revenues are then periodically adjusted in non-rate case proceedings according to a predetermined formula or set of variables (e.g. inflation).

   An earnings sharing mechanism allocates to customers a portion of utility overearnings that exceed (or under-earnings that fall short of) the earnings approved under a multi-year rate plan.

HOW DOES PERFORMANCE BASED REGULATION WORK? HOW IS IT DIFFERENT FROM THE CURRENT SYSTEM?

For a multi-year rate plan, which NERP recommends should be combined with decoupling and PIMs, a utility would still be required to file an initial base rate case to adjust its authorized electric rates and submit cost of service studies. These studies would in turn serve as the basis through which the North Carolina Utilities Commission would determine (1) the total revenue required for the utility and (2) how the revenue would be allocated and collected from the utility customer classes. The proposed performance based regulations, specifically decoupling, PIMs, and the revenue adjustment mechanisms within a MYRP, would adjust, through increments or decrements, any base rates approved in the base rate case.

Decoupling

Once the revenue requirement is established, a decoupling mechanism would provide for periodic rate adjustments to ensure that the utility's actual revenues match its allowed revenues. Therefore, in contrast to the current system, where sales increases result in increased utility revenues, if a utility's sales increased under decoupling, rates would instead be adjusted downward to ensure parity between the utility's actual revenues and allowed revenues. If utility sales decreased, rates would be adjusted upwards to ensure the utility's actual revenues equaled its allowed revenues. As a result, changes in utility sales would have no impact on a utility's revenues, and a utility would no longer be dis-incentivized to pursue energy efficiency savings.

NERP recommends that the legislature authorize the Commission to adopt decoupling. Among other things, NERP suggests that the Commission limit the application of an approved decoupling mechanism to base rates and the residential, small and medium general service customer classes. Detailed suggestions for the Commission are contained in the NERP Guidance on Performance-Based Regulation.[5]

Performance Incentive Mechanisms

Performance incentive mechanisms would condition some portion of a utility's earnings on its performance on certain measurable consumer, utility system, or public policy outcomes. For example, if a utility were to meet identified distributed energy integration or energy efficiency performance targets, it could receive a fixed cash reward, a basis point adjustment to its return on equity, a percentage return on any expenses incurred achieving those targets, or a portion of any shared savings or net benefits created through its achievement of those targets. Conversely, depending on the design of the performance incentive mechanism, a utility might be penalized for failing to achieve those targets. As a result, a utility would have a direct incentive to pursue these outcomes.

This is a departure from the current system, where a large portion of utility earnings stems from the allowed rate of return on certain capital expenditures. Certain PIMs can help to mitigate this capital expenditure (or "capex") bias by providing the utility the opportunity to profit from meeting agreed-upon performance targets.

NERP recommends that the legislature authorize the Commission to adopt performance incentive mechanisms. Specifically, NERP recommends that the Commission consider PIMs that incentivize affordability, carbon reduction, customer service, distributed energy, electrification of transportation, energy efficiency, equity, peak demand reduction, reliability,

[5] The Guidance Document is available with all other NERP outputs on the website at the end of this fact sheet.

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and resilience. Detailed suggestions for the Commission are contained in the Guidance Document.

Multi-Year Rate Plan and Earnings Sharing Mechanism

A multi-year rate plan usually begins with a rate case that determines a utility's initial revenue requirement and establishes how these allowed revenues should be adjusted each year over the course of the rate plan term, which is typically between three and five years. These adjustments can be based on cost forecasts, external indexes, or a combination of both. In contrast to the current system, where the underlying costs recovered in rates reflect prior costs incurred in some previous twelve-month period (referred to as the historic test year), costs and revenues for a multi-year rate plan are forward-looking.

Accordingly, the utility could prospectively identify grid modernization projects and ensure more timely cost recovery for these projects and other investments. In addition, the rate case moratorium could create significant cost containment pressure. A multi-year rate plan that capped a utility's revenues would also incentivize cost containment by providing the utility the opportunity to keep some or all of its cost savings. Given these cost containment incentives, some experts recommend that states adopt targeted PIMs to prevent potential cost cutting from impacting system reliability and customer service.

Subject to Commission pre-approval, an earnings sharing mechanism could specify a formula for sharing any utility cost savings or losses between customers and utility shareholders when utility earnings exceed or fall short of Commission set levels.

NERP recommends that the legislature authorize the Commission to adopt multi-year rate plans and earnings sharing mechanisms. Detailed suggestions for the Commission are contained in the Guidance Document.

HAS PERFORMANCE BASED REGULATION BEEN DONE BEFORE?

Other states

Several other states and international jurisdictions have pursued performance-based regulation. For example, New York is exploring performance based regulation through the Reforming the Energy Vision proceeding before the New York Public Service Commission. Through this proceeding, the Commission has adopted performance incentive mechanisms for distributed energy and other innovative non-wires solutions. In Minnesota, recent legislation, direction from the Minnesota Public Utilities Commission, and extensive stakeholder involvement have resulted in wide ranging performance-based regulation reforms, including a MYRP and decoupling. For more information on the Minnesota PBR development process and outcomes, see the MN PBR Case Study prepared by NERP.[6]

North Carolina

Natural gas decoupling, which is currently authorized under statute, was implemented in North Carolina in 2005. In addition, the North Carolina Utilities Commission has adopted performance incentive mechanisms pursuant to a separate statute to encourage more utility energy efficiency programs and savings.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:
Sally Robertson, NC WARN, sally@ncwarn.org
Laura Bateman, Duke Energy, laura.bateman@duke-energy.com

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

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[6] See the Minnesota case study, available with all other NERP outputs on the website at the end of this fact sheet.

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PBR REGULATORY GUIDANCE

IMPLEMENTATION SUGGESTIONS FOR THE NCUC FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

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ABOUT THE NORTH CAROLINA ENERGY REGULATORY PROCESS

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

ABOUT THIS DOCUMENT

This guidance document contains a detailed discussion of performance-based regulation mechanisms with a specific focus on revenue decoupling, multi-year rate plans, and performance incentive mechanisms. It includes recommendations for the NCUC to consider if and when it begins a process to implement performance-based regulation. The document represents the consensus work of the NERP process stakeholders as of the above date. However, individual NERP stakeholders do not necessarily endorse all of the ideas or recommendations herein.

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SUMMARY OF RECOMMENDATIONS

This document contains recommendations for implementation of performance-based regulation (PBR) developed by the North Carolina Energy Regulatory Process (NERP) participants. The primary intended audience is the NC Utilities Commission (NCUC), as it may be authorized by the General Assembly to develop regulations for PBR. The document contains detailed descriptions of each of the PBR mechanisms discussed in NERP: revenue decoupling, multi-year rate plans (MYRPs), and performance incentive mechanisms (PIMs). NERP participants met throughout 2020 and developed the following recommendations regarding the implementation of PBR.

PBR implementation

1. PBR should be designed to provide for just and reasonable rates and be consistent with the public interest, including the goals of the Clean Energy Plan.
2. PBR for NC should include all three of the mechanisms studied in NERP, as they can work well together to accomplish a broad set of outcomes and stakeholder objectives.
3. Effective PBR will require ongoing monitoring and possible course corrections.
4. A PBR process at the NCUC should consider the conclusions reached by NERP and make sure to receive comment from as broad a group of stakeholders as possible, including representatives from underserved communities with limited access to traditional docket proceedings.
5. The NCUC should, subject to guidance and timelines provided in legislation, begin as soon as possible a proceeding to develop rules for filing, and criteria for evaluating, a comprehensive PBR package including revenue decoupling, a multi-year rate plan, and performance incentive mechanisms or tracked metrics, as well as provisions for annual or more frequent decoupling and MYRP true-ups and adjustments of PIM metrics, targets, and incentive levels.

Revenue decoupling

1. Revenue decoupling should apply to residential and small and medium general service classes. Large general service and lighting do not necessarily need to be included. However, attention should be paid to how excluding any customer class would impact the design of a multi-year rate plan.
2. Revenue decoupling should include all utility functions (generation, transmission, and distribution).
3. Revenue decoupling should include base rates only, excluding riders that have separate true-up mechanisms.
4. Revenue decoupling should include EV charging sales, but a PIM should be adopted related to EV adoption and/or smart charging to incentivize vehicle electrification.
5. Revenue decoupling should utilize either the revenue-per-customer or attrition method for adjusting revenue between rate cases. Decoupling adjustments to the allowed revenue would be impacted by the MYRP design as well, so the interplay of these two mechanisms should be noted.
6. The amount of adjustment to customer rates under decoupling should be capped, and the design of refunds and surcharges should consider ways to encourage energy efficiency.
7. Rate adjustments should occur once a year.
8. The NCUC will need to consider the above issues, as well as ways to encourage utilities to pursue beneficial electrification when decoupled.

Multi-year rate plan

1. The mechanism for adjusting rates should be defined at the outset of a MYRP.
2. A maximum of three years should be the term of an initial MYRP.
3. A MYRP should not be used to recover costs for large, discrete investments, such as a conventional power plant. Investment programs that are made up of a series of smaller utility assets placed in service over time are well-suited for a MYRP.
4. A MYRP should be accompanied by a pre-set earnings sharing mechanism to share savings between customers and utility stockholders. The mechanism could include sharing tiers and a “deadband” of over- or underearning in which no adjustment is made.

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5. The NERP team did not come to consensus on whether MYRP should cover base rates or be more narrowly constructed to cover only certain projected costs.
6. The NCUC should determine the general conditions under which a MYRP may be revised or revisited.

Performance incentive mechanisms

1. PIMs should adhere to a set of principles to help align stakeholders on shared objectives and guide PIM design.
2. At the outset, utilities should track as many metrics as are deemed useful and cost-effective. This document lays out recommended metrics.
3. The utility should track the overall performance for each adopted PIM or tracked metric, and, where possible, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties.
4. The utility should establish a public dashboard for reporting performance on PIMs and tracked metrics.
5. The following outcomes should be targeted for PIM and/or tracked metric development:
    a. Peak demand reduction
    b. Integration of utility-scale renewable energy and storage
    c. Integration of distributed energy resources
    d. Low-income affordability
    e. Carbon emission reductions
    f. Electrification of transportation
    g. Equity in contracting
    h. Resilience
    i. Reliability
    j. Customer service
6. The NCUC will need to evaluate the appropriateness of any proposed performance incentive assigned to each potential tracked metric.

INTRODUCTION

Purpose and objectives

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) with regard to performance-based regulation (PBR) to the NC Utilities Commission (NCUC) as it may be authorized by the General Assembly to develop rules for PBR. It may also be of interest to the NC General Assembly and other parties who want more information on PBR or the NERP process than is provided in the companion fact sheet.[1]

Duke Energy's Climate Report[2] and Dominion Energy's Sustainability and Corporate Responsibility Report[3] set ambitious goals for reducing carbon emissions. The NC Clean Energy Plan[4] calls for the state's electric power sector to reduce greenhouse gas emissions 70% below 2005 levels by 2030 and attain carbon neutrality by 2050, transitioning to cleaner energy resources while growing the state's economy. As detailed below, however,

[1] All NERP PBR companion documents can be found at the following location: https://deq.nc.gov/CEP-NERP

[2] *Achieving a Net Zero Carbon Future: Duke Energy 2020 Climate Report*, https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

[3] *Building a Cleaner Future for Our Customers and the World, 2019 Sustainability and Corporate Responsibility Report*, Dominion Energy, https://sustainability.dominionenergy.com/assets/pdf/Dominion-Energy_SCR-Full-Report-FY2019.pdf.

[4] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

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the current cost of service (COS) ratemaking[5] system for the state's investor-owned utilities (IOUs) does not provide the proper utility incentives for timely and efficient accomplishment of these goals at reasonable cost.

NERP stakeholders have determined that better alignment of incentives would be created by transitioning the state to a comprehensive PBR framework.

This document communicates NERP's recommendations for designing a PBR system that would benefit North Carolina.

Improved Utility Regulations for North Carolina's Energy Transition

PBR offers a suite of reforms that, together, can resolve limitations of COS ratemaking while encouraging utilities to better serve state policy goals and customer interests. In North Carolina, this includes decarbonization of the power system, accelerated adoption of clean energy technologies including new customer service opportunities from distributed energy resources (DER), alleviating low-income energy burden, and reduction of costly administrative burdens and regulatory lag.[6]

Three PBR mechanisms are the focus of this document, and NERP suggests they be jointly considered and designed for NC electric utilities:

- Decoupling to remove the utilities' incentive to grow energy sales
- Performance incentive mechanisms (PIMs) to create new earnings opportunities (or penalties) for targeted outcomes
- Multi-year rate plans (MYRP) to increase the time between utility rate cases in order to introduce cost containment incentives for the utility and reduce regulatory lag

PBR design and adoption is a significant undertaking. Critical details must be considered and worked through, typically through a regulatory proceeding that includes utility proposals, input and counterproposals of other stakeholders, and eventual decision-making by utility regulators. As outlined below, a probable first step will be enactment of PBR-enabling legislation.

Companion documents

In addition to this guidance document, NERP has produced:

- Draft legislation authorizing the NCUC to pursue PBR
- A fact sheet providing an introduction to PBR, an overview of the draft legislation and a summary of this guidance document
- Case studies discussing:
  - how PBR has been implemented in Minnesota, and
  - how North Carolina has implemented revenue decoupling for natural gas utilities.

Context and history

On October 29, 2018, Governor Roy Cooper issued *Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy*.[7] The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

[5] According to NARUC, "In Cost of Service Regulation, the regulator determines the Revenue Requirement—i.e., the 'cost of service'—that reflects the total amount that must be collected in rates for the utility to recover its costs and earn a reasonable return." https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB. Under the proposed PBR system, the utility would still file cost of service studies in a general rate case and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base.

[6] Regulatory lag results when a utility's costs change, either up or down, in between rate cases. Issues result when regulatory lag creates financial incentives for utilities that are not aligned with public interest. For more detail, see Appendix A.

[7] Executive Order 80. https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-climate-change-and-transition.

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DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System* (CEP).[8] Recommendation B-1 of the CEP states: "Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation." That process was launched as NERP, which met throughout 2020.

Also relevant to this document is NC Senate Bill 559,[9] introduced in 2019. SB559 eventually passed and authorized utilities to petition the NCUC to recover certain storm recovery costs through securitization. The initial version of the bill included a separate section that would have authorized the NCUC to accept MYRP proposals from utilities. After concerns were raised by a large number of stakeholders, and no adequate compromise was found, that section of the bill was dropped. NERP has attempted to recognize the advantages of – and resolve the objections to – the MYRP as proposed in SB559.

NERP process

The NERP process, facilitated by Rocky Mountain Institute and the Regulatory Assistance Project, brought together roughly 40 diverse stakeholders to consider four main avenues of utility regulatory reform:

- PBR
- Wholesale market reform
- Competitive procurement of resources
- Accelerated retirement of generation assets

The NERP stakeholder group identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1. Of those, the focus of PBR deliberations were:

- Regulatory incentives aligned with cost control and policy goals
- Carbon neutral by 2050
- Affordability and bill stability

[8] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[9] SB559, Storm Securitization, passed Oct. 2019, https://www.ncleg.gov/BillLookUp/2019/s559.

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Outcome Category	Outcome
Improve customer value	Affordability and bill stability ★
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve utility regulation	Regulatory incentives aligned with cost control and policy goals ★
	Administrative efficiency
Improve environmental quality	Integration of DERs
	Carbon neutral by 2050 ★
Conduct a quality stakeholder process	Inclusive
	Results oriented

FIGURE 1: PRIORITY OUTCOMES IDENTIFIED BY NERP STAKEHOLDERS

PBR Study Group

A subset of NERP participants volunteered to serve on a PBR study group and began meeting in May 2020. Three subteams were created to discuss: revenue decoupling, multi-year rate plans (and earnings sharing mechanisms), and performance incentive mechanisms. (See page 2 for a list of PBR study group and subteam members.)

The subteams regularly presented their work to the PBR study group for feedback. The study group presented a straw proposal to the larger NERP group, detailing how a comprehensive PBR package might be designed for NC. Feedback was received from NERP participants and incorporated into the eventual design recommendations detailed below.

What problems is PBR solving?

Performance-based (or outcome-based) regulation is intended to motivate utilities to accomplish outcomes that customers or society deem desirable. In doing so, PBR can help shift utility focus away from certain outcomes that may be inadvertently incentivized by traditional ratemaking.

In the current system, utilities increase their revenues by increasing electricity sales in the short term (known as the throughput incentive) and increase their profits by favoring rate-of-return-based utility capital spending over other options as the method by which to solve identified grid needs (known as the capital expenditure, or capex, bias).

The throughput incentive arises from the fact that, in traditional ratemaking, prices are set primarily on a volumetric basis based on a historic level of costs and sales, normalized and adjusted for known and measurable changes. After volumetric prices are set in the rate case, if utilities sell more electricity than was estimated in the rate case, they increase their revenues and therefore profits (assuming costs do not fluctuate significantly based on sales volume in the short term).

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The capex bias originates from the fact that utilities are typically allowed to earn a regulated rate of return (profit percentage) on shareholder capital that they invest in physical assets, such as power plants, transmission wires, distribution grid assets, company trucks, computers, buildings, etc. This results in utility preference for capital expenditures as solutions for grid needs, whereas many cost-saving or emissions-reducing opportunities result from program innovations, such as customer efficiency programs, that fall into the category of operating expenditures (opex), on which no rate of return is earned.

Even as NC's population is growing, the demand for electricity from existing customers continues to remain flat, and in some cases has declined compared to historical years as more customers are investing in their own on-site generation and energy efficiency measures. This changing economic landscape can further drive the throughput incentive and capex bias, the two main limitations of the current framework.

PBR offers a set of tools that can create utility incentives that are more aligned with customer and societal goals. For example, PBR can make it more likely that clean energy, energy efficiency, and carbon reduction goals are achieved. There is no one uniform combination of PBR tools. Some states have implemented one or two reforms; others are examining comprehensive measures. The reforms discussed below were the focus of NERP and have been implemented or are currently being discussed in other states.

See Appendix B for a diagram depicting potential interactions and coordination between the different mechanisms within a PBR framework.

Other ongoing processes and trends impacting PBR

The world in general, and North Carolina in particular, are in an exciting period of transition to a cleaner and more equitable electricity system. As a result, there are emerging technologies, rapidly changing cost dynamics, potential new policies, and revisions of old policies all up in the air at once. NERP has designed recommendations for PBR implementation based on its best estimate of where these balls might land.

In considering any PBR proposal that comes before it, the NCUC will have to evaluate where these processes stand and how the PBR mechanisms interact with them. Some examples of ongoing processes include:

- other proposals emerging from the NERP process (securitization of uneconomic coal assets, all-source competitive procurement, and wholesale market study),
- an analysis of carbon reduction policies under the A-1 recommendation of the CEP including accelerated coal retirements; a Clean Energy Standard or other clean energy policy (e.g., Energy Efficiency Resource Standard or Peak Reduction Standard); an offshore wind requirement; a carbon adder or shadow carbon price for purposes of planning and/or dispatch; and/or a market-based cap and invest program (e.g., joining the Regional Greenhouse Gas Initiative),
- the Southeastern Energy Exchange Market proposal being advanced by Duke Energy and other Southeast utilities,
- the trend toward vehicle electrification and state strategies for accelerating adoption of electric vehicles, including the NC Zero-Emission Vehicle Plan, Duke's EV pilot, distribution of VW Settlement Funds, and NC signing onto the multistate Medium- and Heavy-Duty ZEV MOU,
- the low-income collaborative proposed by Duke Energy in the current NC rate cases,
- the comprehensive rate design study proposed by Duke Energy in the current NC rate cases,
- implementation of changes to the EE/DSM incentive ordered by the NCUC in its October 2020 order, including new incentive levels and use of the Portfolio Performance Incentive and Utility Cost Test,[10]
- any changes to net metering policy,
- NCUC orders that will be issued on DEC and DEP rate cases and Duke's Integrated Resource Plan,

[10] Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d.

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- the NC Transmission Planning Collaborative's study of onshore transmission investments necessary to integrate up to 5,000 MW of offshore wind (expected completion in early 2021),
- the newly established nonprofit NC Clean Energy Fund that will make funding available for clean energy projects that are traditionally difficult to finance, and
- Duke Energy's implementation of its Integrated System & Operations Planning (ISOP) process that will allow integration of new technologies and customer programs as technology and policy pertaining to generation, transmission, and distribution continue to evolve.

Some of these factors are flagged in the specific recommendations below.

Statutory authority and rationale for legislation

Legislation has been used in many states to provide explicit authority to utility commissions to implement or approve proposed PBR mechanisms. In the expectation that the NCUC would welcome specific authorizing legislation, NERP has drafted legislation authorizing the NCUC to pursue comprehensive PBR. It specifies deadlines and baseline requirements that any PBR package should meet, but is minimally prescriptive so that the NCUC has leeway to consider the many PBR design parameters in a manner that best meets the needs of the state at the time the mechanisms are established.

NERP RECOMMENDATIONS FOR PBR TOOLS

After studying the PBR mechanisms described below, NERP has come to the conclusion that a comprehensive package of revenue decoupling, multi-year rate plan, and performance incentive mechanisms would best address North Carolina's changing needs. The three sub-sections below explain how each mechanism works, how the mechanisms interact with each other, what recommendations NERP makes for their design, and key issues that need attention from the NCUC. NERP participants offer the following takeaways and recommendations from our deliberations on PBR to inform the NCUC's thinking.

Revenue Decoupling

Definition

Decoupling breaks the link between the amount of energy a utility delivers to customers and the revenue it collects, thus minimizing the throughput incentive described above. Allowed revenue is set in a rate case as usual. Rather than setting prices in the rate case and leaving them unchanged until the next rate case, under revenue decoupling prices are set in the rate case but adjusted up or down over the course of the rate effective period to ensure that collected revenues equal allowed revenues (no more and no less). See Figure 2.

Traditional System:

Revenue = Fixed Price × Sales

Decoupled System:

Price = Fixed Revenue ÷ Sales

Comparison with current system

Currently, for many residential and smaller commercial and industrial rate schedules, there are no demand charges and a majority of fixed costs are recovered through variable energy rates (cents per kWh). When fixed costs are recovered through a variable rate, a utility's margin is higher when it increases its sales and lower when it decreases its sales. Consequently, the utility has a financial incentive to increase sales and a disincentive to reduce sales. Decoupling seeks to break this linkage.

This incentive and linkage have already been recognized by the NCUC in its approval of net lost revenue mechanisms within utility energy efficiency and demand side management riders.

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The net lost revenue (NLR) mechanism addresses this issue by removing the financial disincentive to reduce sales when the utility implements an approved DSM/EE program. Decoupling goes a step further by removing the incentive/disincentive to increase or reduce sales in all situations. This would include reduced sales from DER deployment, reduced sales from customer efficiency and conservation efforts that are not part of a utility program, and reduced sales from certain rate designs or other utility programs that may not qualify as an approved DSM/EE program. It would also break the incentive for increases in sales from electric vehicle charging and economic development. Since some of these sales may align with the public interest, it is important to implement decoupling as part of a comprehensive PBR package to ensure that the utility still has an incentive to beneficially grow sales in areas that are aligned with public interest.

Decoupling is one part of broader PBR plan

Many states implement decoupling as part of a broader PBR package and there are synergies between the mechanisms. For example, PIMs can be used to incentivize electric vehicle charging or economic development when decoupling removes these incentives from the current ratemaking structure. Additionally, where decoupling removes a disincentive for the utility to reduce sales through energy efficiency or other means, PIMs can go a step further and create a positive incentive for the utility to reduce sales. Decoupling also works well with multi-year rate plans. The MYRP can provide for small, annual changes in rates, and the decoupling mechanism can true-up the sales that the MYRP rates are based on to actual sales realized during each year of the plan. Thus, decoupling and MYRPs together can reduce the need for frequent rate cases and can break the linkage between utility sales and profit margin.

Alignment with the goals of the Clean Energy Plan

Decoupling is aligned with the broader CEP goals. First, the CEP supports increased DERs, EE, and DSM, all of which decrease sales per customer. Decoupling removes the sales-related disincentive utilities have to promote and utilize these resources. Decoupling is also an alternative to increasing fixed charges in the rate design structures for residential and smaller commercial and industrial customers. If fixed costs are recovered through fixed charges and variable through variable, this also removes the throughput incentive for utilities. However, increasing fixed charges also decreases variable charges, which reduces the incentive for customers to be energy efficient, conserve energy, and/or invest in DERs. Additionally, higher fixed charges, on average, place a higher energy burden on low-income customers, who tend to have lower usage per customer. Reducing the incentives for EE, conservation, and DERs and placing a higher energy burden on low-income customers are contrary to the goals of the CEP. Decoupling is therefore better aligned with the goals of the CEP than increasing fixed charges as a means of removing the throughput incentive.

Experience in other states and jurisdictions

North Carolina has experience with decoupling in the natural gas distribution sector.[11] In addition, electric decoupling has been adopted successfully in 17 states and another 7 states have pending actions. Rate adjustments under decoupling are typically small. According to a 2013 report produced for the American Council for an Energy-Efficient Economy and the Natural Resources Defense Council, almost two-thirds of adjustments made under decoupling were within 2% of the retail rate and 80% within 3%. Such adjustments are modest compared to other utility expenses that influence rates.[12]

Design Details of Decoupling and NERP Recommendations

The utility's proposed decoupling mechanism must be evaluated to ensure that it will produce just and reasonable rates and is consistent with the public interest, including the goals of the CEP. NERP explored several key design components of decoupling mechanisms, and has the following recommendations.

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[11] Case Study: Natural Gas Decoupling in North Carolina, NERP, December 2020, available here: https://deq.nc.gov/CEP-NERP.

[12] https://www.aceee.org/sites/default/files/publications/researchreports/u133.pdf

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Decide what is covered

Affected Classes: Because the primary rate schedules that recover fixed costs through variable rates are the residential and small to medium general service, we recommend that these classes be included. The rate design for large general service includes demand charges and other provisions to recover more of the fixed costs through fixed charges. Also, lighting rate schedules generally recover fixed costs through fixed charges. When only variable costs are recovered through variable rates, there is no throughput incentive (revenue and costs go up or down proportionally and there is no impact to margin from higher or lower sales levels). Large general service and lighting do not necessarily need to be included for the decoupling mechanism to be effective and the NCUC may determine that it makes more sense to exclude them from the mechanism. However, attention would need to be paid to how excluding these customers from decoupling might impact the design of a utility's MYRP.[13]

Including small to medium general service in the decoupling mechanism would introduce a complexity that NERP did not have time to work through. Decoupling would replace the current net lost revenue mechanism recovered through the DSM/EE rider for classes participating in decoupling. Because there is only one general service rate in the DSM/EE rider for all three general service classes (small, medium, and large), it may not be feasible to include net lost revenues for only one of the three sizes in the rider. Consideration also needs to be given to small and medium general service accounts that can currently opt out of the net lost revenue mechanism and how that will be addressed with decoupling.

Costs to include:

- Recommend including all functions (generation, transmission, and distribution). In order for the mechanism to be effective and completely address the throughput incentive, it should not exclude any function included in the utility's bundled rate.
- Recommend including base rates only and excluding riders that have separate true-up mechanisms. If a rider already has a mechanism to true-up for sales volume (like fuel), then it should be excluded from the decoupling mechanism. If a rider does not have a separate true-up mechanism for sales, it may be included.
- The PBR study group considered recommending excluding EV charging sales in order to maintain the utility incentive to promote vehicle electrification. However, the only state where we have seen this done is Minnesota, and it may overly complicate the mechanism. Therefore, NERP recommends including EV charging sales in the decoupling mechanism and simultaneously adopting a PIM related to EV adoption and/or smart charging.

[13] Large industrial customers are excluded from decoupling in some states on account of possible rate volatility should a single very large user leave the utility territory or change operations. Different treatment between customer classes is complicated, however, when decoupling is part of a MYRP framework. In many states with comprehensive MYRPs , such as California, Minnesota, Hawaii, and Massachusetts, decoupling is applied to all major customer classes. See Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, November 2016. http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf; Minnesota Public Utilities Commission, "Order Approving True-Ups and Requiring Xcel to Withdraw its Notice of Changes in Rates and Interim Rate Petition," March 13, 2020.

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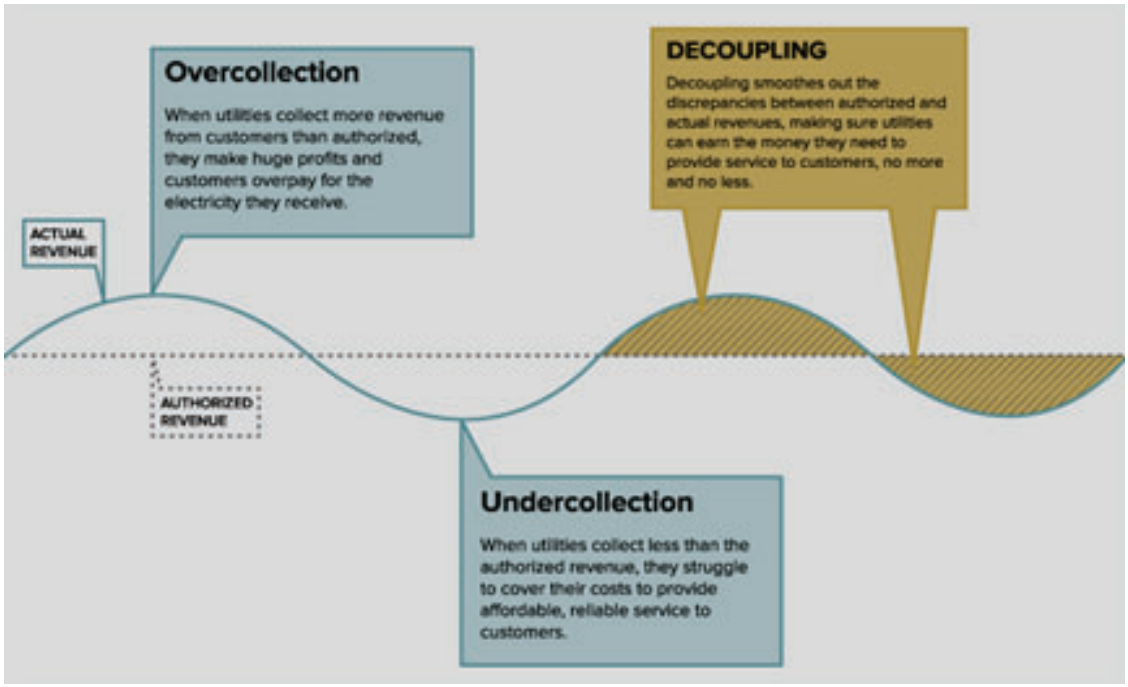

FIGURE 2: HOW DECOUPLING SMOOTHS OUT REVENUE FLUCTUATIONS[14]

Choose how to adjust utility revenue

The team explored several methods of adjusting the annual revenues under a decoupling mechanism and recommends consideration of the following two options: Revenue Per Customer (RPC) and Attrition Adjustment.

- RPC – allows for increases in revenue as new customers are added to the system, but mitigates changes in revenue driven by changes in usage per customer. In the initial base rate case, a revenue requirement per customer is set for the affected classes. Periodically, the actual revenue received from a class is compared to the target revenue per customer times the number of customers. Any excess or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. In addition, the tariff rates used going forward may be adjusted to reflect changes in usage per customer. This going-forward adjustment would need to be made in conjunction with any adjustments in the MYRP.

  Target revenue = number of customers x revenue requirement per customer

  This method is fairly straightforward and consistent with the current mechanism for gas utilities in NC; however, some NERP participants expressed concerns that actual costs per customer may decline over time, especially if generation assets (which depreciate over time) are included in the mechanism. If this is the case, some experts suggest that an attrition adjustment method may be more appropriate.[15]

- Attrition - adjusts the fixed level of revenue to be collected based on changes in costs and sales. This method may be appropriate when generation assets are included in decoupling. Just like with RPC, the actual revenue received from a customer class is compared to a target level of revenue, and any excess

[14] Nissen Will, "Strategic electrification and revenue decoupling: different purpose, same goal," May 2, 2018, Fresh Energy, https://fresh-energy.org/strategic-electrification-and-revenue-decoupling-different-purpose-same-goal/.

[15] Migden-Ostrander, J., and Sedano, R. (2016). Decoupling Design: Customizing Revenue Regulation to Your State's Priorities. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities

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or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. However, the target revenue is based on the actual costs incurred over the same period and may be based on a formula rate template or agreed-upon formula adjustments to the rate case test year cost of service study. These "attrition review" proceedings are sometimes referred to as "mini-rate cases" but are a streamlined alternative to full-blown rate cases.

It should be noted that, under both types of decoupling, the going-forward adjustments would need to be coordinated with adjustments under the multi-year rate plan. This linkage is one way in which decoupling and MYRP work well together. MYRP involves a detailed analysis of how utility revenue should be allowed to adjust over time, while decoupling ensures that the allowed revenue is recovered (but not more or less than the allowed revenue).

If both decoupling and a MYRP with a revenue cap are adopted, the details of the two mechanisms must be determined together. The MYRP will likely inform how allowed revenues adjust each year, while decoupling will adjust customer rates so collected revenues equal allowed revenues. Options to adjust revenues may be based on inflation or other index, multi-year cost forecasts, customer growth, or a hybrid approach.

Select how to handle refunds or surcharges.

The process for the annual adjustment to rates should be efficient and transparent. NERP recommends considering caps on annual impacts to customers, with any additional amounts deferred into a future period. NERP also recommends considering design options for handling refunds and surcharges that encourage greater energy efficiency.

In terms of frequency of adjustments, NERP recommends decoupling price adjustments once a year. Some mechanisms are updated monthly, but that could lead to customer confusion with too-frequent price adjustments. According to a 2012 survey,[16] over two-thirds of electric utility decoupling true-ups were conducted on an annual basis.

Multi-year rate plan & earnings sharing mechanism

Definition

A MYRP begins with a rate case that sets the utility base revenues for the test year, based on the normal ratemaking process.

Under a MYRP, the revenue requirements necessary to offset the costs that are contemplated to occur under a plan approved by the NCUC would be set for multiple years in advance (typically 3–5 years). Utility compensation would be based on forecasted costs that are expected under the NCUC-approved plan, rather than the historical costs of services. Customer rates would be reset annually through NCUC review under the terms set out for the MYRP.

This approach can create added incentives for the utility to contain costs and can also reduce the regulatory costs from more frequent rate cases. The terms of a MYRP often include the following:

- A moratorium on general rate cases for longer periods (the term of the MYRP).
- Attrition relief mechanisms (ARMs) in the interim to automatically adjust rates or revenue requirements to reflect changing conditions, such as inflation and population growth.

[16] Morgan, P. *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations.* Graceful Systems LLC, rev. February 2013, https://www.raponline.org/wp-content/uploads/2016/05/gracefulsystems-morgan-decouplingreport-2012-dec.pdf.

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- MYRPs can (1) mitigate the regulatory lag associated with certain utility assets, such as grid investments and DERs, (2) give an incentive for utility cost containment by setting a framework for predictable revenue adjustments into the future.
- To maintain or pursue other regulatory and policy goals, MYRPs should be combined with performance incentive mechanisms (PIMs) (sometimes considered "backstop" protections for reliability or other services), an earnings sharing mechanism, and other tools.

Comparison with current system

The current system in NC is a traditional cost of service (COS) ratemaking system, which uses historical test years for base rate cases. This system has evolved over the years with the additions of selected cost recovery riders/clauses (e.g., fuel, etc.).

The types of assets to be added to the utility system in the future (renewables, energy storage, and grid improvements) will consist of a series of smaller, more frequent projects, and the addition of any large, central station generation assets will become rarer and rarer. The existing base rate case process does not fit this future well – the utility suffers significant regulatory lag, and so must file rate cases frequently, even annually. Utilities do have the incentive to reduce their costs between rate cases, but when rate cases become so frequent that they are almost annual, this cost reduction incentive is reduced. The NCUC still determines in each rate case what a reasonable level of costs is, but there is less incentive for the utility to try to drive costs below this level.

NERP believes that modifying the existing COS regulation to include a combined package of performance-based ratemaking provisions, including establishing MYRPs with an earnings sharing mechanism, revenue decoupling, and PIMs, will facilitate accomplishment of the goals delineated in the CEP.

MYRPs are one part of a broader PBR plan

MYRPs seem to work well with decoupling – many states currently use both at the same time. Additionally, MYRPs can work well with PIMs by establishing the cost recovery plan for investments that will achieve a goal and then creating a financial incentive or penalty for achieving or failing to achieve that goal. For example, to encourage increases in electric vehicle adoption or distributed energy resources, a multi-year rate plan can include the investments the utility must make to achieve these goals and then a PIM can attach a financial incentive to the goal. Neither a PIM without the enabled cost recovery through a MYRP, nor a MYRP without the accountability of a PIM, are as effective as the two mechanisms working in combination.

MYRP alone would not do anything to specifically address other policy goals such as the reduction of household energy burden, however. Addressing these key goals, and others under the CEP, would require the use of specific PIMs, or other requirements being placed on the utility, along with implementing the MYRP. See also the section below on PIMs.

Because of the complementary nature of the mechanisms, NERP recommends that MYRPs, decoupling, and PIMs be implemented in combination as part of a comprehensive PBR package.

Alignment with the goals of the Clean Energy Plan

One of the top three desired outcomes identified by NERP is to create "utility incentives aligned with cost control and policy goals."

MYRPs may give the utility the incentive to control and reduce its costs by giving it the opportunity to keep some of the cost savings as long as the MYRP is coupled with an earnings sharing mechanism. This cost containment incentive could potentially help address the utility's capex bias by motivating the utility to choose the most cost-effective solutions for grid needs, regardless whether they are capex or opex.

The effect of MYRPs in reducing regulatory lag on the kinds of new investments needed under the CEP is another key alignment of utility incentives with policy goals.

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Also, page 12 of the CEP states:

> *The following overarching recommendations are critical to the transition and will drive the priorities identified by the stakeholders:*
> - *Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.*
> - *Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.*
> - *Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.*

Significant investments will need to be made to modernize the grid consistent with these recommendations. MYRPs are a way to address the current financial disincentive that utilities have to make significant investments in the grid (see Appendix A) and therefore support the CEP priorities.

Experience in other states and jurisdictions

Fifteen US states have adopted electric utility MYRPs. Examples with a longer experience of MYRPs include Central Maine Power, MidAmerican Energy, and utilities in California and New York (MYRPs are also common in Canada, including Ontario). In our region, Georgia Power has been under MYRPs since the mid-1990s, and FP&L has used these repeatedly in Florida. The PBR study team reviewed a series of reports and studies of the other states to attempt to learn from the experiences of others. That review shows that while MYRPs show significant promise, there are many examples that indicate MYRPs must be enacted carefully. While our review was not exhaustive, the following are some of the key insights:

- Setting up MYRPs is a complicated process. It will require a lot of work from all stakeholders, and is fraught with risk of errors in the initial design that can have large consequences. The initial design can and should be improved over the years to correct any initial difficulties. Nevertheless, the PBR study team feels that the benefits of successfully implementing MYRPs – when coupled with an appropriately-designed earnings sharing mechanism – make this worth the effort, and the attendant risks can and should be mitigated and corrected.
- *The oversight of the NCUC should not be reduced.* Under a MYRP, the NCUC would be able to see the utility's business plans for a period of years into the future – which does not happen under the current system. This would allow for discussion of the types and amounts of assets to be added to the grid before the fact, instead of after the fact. Additionally, the NCUC would have detailed reviews of utility costs before each increase under a MYRP is authorized.
- There should be monitoring of utility service levels to mitigate the risk that utilities with a stronger incentive to reduce costs under a MYRP do not let existing service levels suffer. The use of a PIM with penalties for degradation of basic reliability and service levels outside of reasonable norms should be considered.

Examples of comments extracted from one report[17] that the team used as a reference:
"…It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design."

[17] Deason, J, et al. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities." 2017, pp. 7-2,7-3. https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

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"…The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay."
"…We also found that the [productivity] growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs."

Design Details of MYRPs and NERP Recommendations

The mechanism for adjusting rates between rate cases must be clearly defined at the outset in the initial rate case. It is crucial for the rate adjustments to be defined at the outset to ensure a high degree of certainty of how the adjustments will be subsequently made. The utility is then clear about the extent to which a successful effort to control costs will result in increased earnings. Rider/trackers, true-ups, deferral accounts, and similar mechanisms are often used to address the need for additional expenditures or investments separately from rate cases to reduce the utility's exposure between rate cases.

The term of the MYRP

NERP recommends using a maximum of three years as the term of an initial MYRP, but this is a key term to be decided. While most MYRPs are 3-5 years, NERP recommends starting on the shorter end of this range until more experience with the mechanism is gained. At the expiration of the MYRP, the utility would have the right, but not the obligation, to come in and seek a base rate increase. The NCUC could also set a period within which the next base rate case must be filed (e.g., within 5 years).

The scope of the MYRP – which utility costs would be included?

The MYRP would not necessarily apply to all utility costs. The selection of which costs should be included in the MYRP is a key term to be decided, and each of the other states studied appears to have made specific decisions that fit their needs best.

MYRPs are not well suited for the ratemaking for large, single discrete investments, such as conventional power plants to be built and rate-based by the utility. These would normally be excluded from the MYRP design and handled separately, through a deferral or separate base rate adjustment.

Costs recovered through existing clauses, such as the fuel clause, would stay in their clause, and not be included in the MYRP.

Investment programs that are made up of a series of smaller utility assets constantly placed in service over time, such as a grid improvement plan, are very well suited to a MYRP.

An earnings sharing mechanism should be implemented

As the MYRP design sets utility revenue adjustments into the future and creates an incentive for the utility to keep its costs lower than those assumed in the MYRP, the possibility of either over- or underearnings during the term of the MYRP should be addressed when the MYRP is designed.

NERP recommends that the MYRP be accompanied by a preset earnings sharing mechanism (ESM). This would set out the details in advance of how the savings will be allocated between the customers and the utility stockholders.

The ESM could be symmetrical, with earnings above and below the allowed return shared between customers and stockholders according to the method set out by the NCUC when the plan is originally approved. The earnings sharing would be calculated on an annual basis.

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Key issues requiring further discussion by the NCUC

Some MYRP design decisions that were either controversial or otherwise unresolved during NERP are flagged here as important for continued attention in the course of the PBR design process.

Determination of what costs to include under MYRP

The NCUC will need to determine whether a MYRP should cover base rates or be more narrowly constructed to only cover certain projected costs. This decision will inform the initial utility revenue requirement the NCUC approves at the beginning of a MYRP and how these allowed revenues might adjust in the interim years between rate cases. Commissions have typically allowed MYRPs to cover most utility costs to more comprehensively impact utility spending decisions.

If the scope of the MYRP is too narrow, the utility may not be able to commit to a multiple-year rate case "stay-out" or moratorium, depending on the planned investments over that period.

On the other hand, risks to ratepayers can be minimized by limiting the scope of costs that may be recovered under a MYRP, so some stakeholders favored using the following definition developed during SB559 negotiations:

> "Multiyear rate plan" means a rate mechanism under which the Commission sets base rates and revenue requirements for a multiyear plan period based on known and measurable set of capital investments and all the expenses associated with those capital investments and authorizes periodic changes in base rates during the approved plan period without the need for a base rate proceeding during the plan period.

Course correction if MYRP produces undesired outcomes

The longer stay-out period of a MYRP introduces risk that utility earnings could exceed or be below target levels, resulting in excessive over- or underearning by the utility. This may result from unforeseen events (e.g., tax law changes, economic recession) or from unexpected consequences of regulation design in the MYRP. Provisions can be made in the adoption of a MYRP for regulatory review at interim points in the plan, or for "reopeners" or "off ramps" at the determination of the NCUC, should those be necessary. It is useful for adopted regulations to specify that the NCUC may conduct such reviews or reopeners, including under what general conditions a plan may be revised, although the NCUC does not need to be overly specific on conditions under which this can occur.

Revenue adjustment mechanisms

See above under revenue decoupling for a discussion of the need to consider decoupling and MYRP revenue adjustments together.

Earnings sharing mechanism design

NERP recommends adopting a MYRP in conjunction with an ESM, but did not discuss the particulars of ESM design. Some issues to be resolved include whether there should be a deadband of over- or underearning in which no adjustment is made, and how sharing tiers should be designed.

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Performance incentive mechanisms

Definition

Performance incentive mechanisms (PIMs) establish performance targets and tie a portion of a utility's revenue to its performance on meeting those targets. Targets are set to achieve outcomes that align with public policy goals.

Comparison with current system

One of the top three goals identified by NERP is to create "utility incentives aligned with cost control and policy goals." The COS model incentivizes utilities to sell more electricity and to add capital assets to their rate base, but those incentives do not necessarily align with public policy goals such as the need to quickly reduce carbon emissions or alleviate household energy burdens. Introduction of carefully designed PIMs into ratemaking procedures could bring utility incentives more in line with public policy goals, such as meeting the state's targets under the Clean Energy Plan, by linking a portion of utility revenues to utilities' performance in achieving those goals.

If a significant portion of a utility's revenues is tied to performance, PIMs can begin to shift a utility's investment or management focus away from increasing capital assets and toward the accomplishment of the public policy objectives reflected in PIMs, potentially mitigating the utility's capex bias.

North Carolina has already started down the PIMs path, as the shared savings mechanism under the EE/DSM rider is a PIM incentivizing performance in the areas of energy efficiency and demand-side management.

PIMs are one part of broader PBR plan

As described elsewhere in this document, PIMs complement both decoupling and multi-year rate plans. Decoupling removes the utility's disincentive to promote energy efficiency and DERs, and PIMs can be designed to go further and create incentives for utilities to promote these programs. A MYRP creates an incentive for a utility to cut costs, and it can be paired with PIMs designed to make sure the cost-cutting does not occur in a way that negatively impacts essential functions such as customer service and reliability.

Alignment with goals of the Clean Energy Plan

The purpose of PIMs is to align utility incentives with public policy goals, which is one of the main outcomes sought by the CEP. In addition, the PIMs recommended below by NERP address the following CEP goals: carbon reduction, energy efficiency, affordability, and clean energy deployment.

The PIMs recommended below are those that seemed most useful to NERP participants. The NCUC could consider additional PIMs to help meet other goals and ensure successful implementation of PBR, as long as the desired outcomes are ones over which the utility has some level of control.

Experience in other states and jurisdictions

Several other jurisdictions have implemented, or are studying, PIMs. Two resources that relate their experiences are *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (Whited, et al., 2015) and *PIMs for Progress* (Goldenberg, et al., 2020) (see References below).

Design Details of PIMs and NERP Recommendations

Metrics, Targets, and Incentives

The first step in establishing PIMs is to decide on the desired outcomes. For each outcome, it must be determined whether a reward or penalty is necessary. Among other things, this inquiry rests on existing utility

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incentives (and disincentives), the existing regulatory environment, and the level of utility control over the desired outcome. The next step is to identify what metrics will be used to measure utility performance. The collection of some amount of baseline data is typically needed in order to determine how a utility's performance is changing over time and how a reward or penalty ought to be implemented.

Depending upon whether a reward or penalty is appropriate, and depending on the level of confidence in a particular metric, performance on selected metrics can be (1) tracked and reported, (2) scored against a target or benchmark that has been set, or (3) tied to a financial reward or penalty, at which point the mechanism becomes a PIM.

For PIMs, if the utility achieves its performance target, it can then receive a financial reward or it can avoid a penalty. PIMs can be either symmetrical or asymmetrical. If the PIM is symmetrical, the utility receives a financial reward for achieving the target as well as a penalty for falling short of the target. An asymmetrical PIM provides only a reward ("upside only") or only a penalty ("downside only").

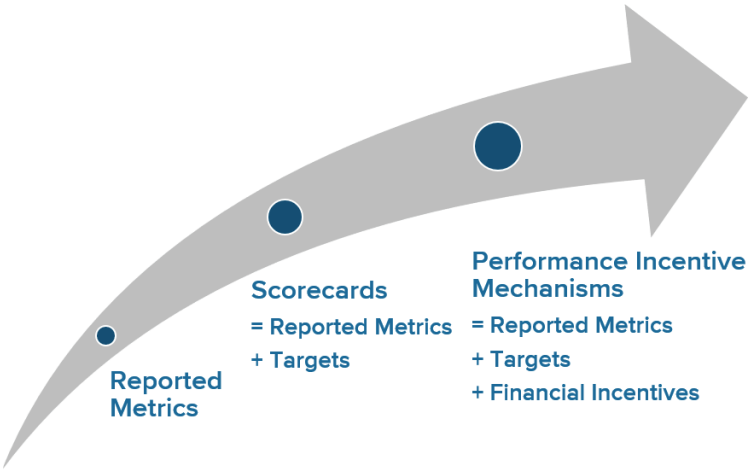

FIGURE 3: STAGES OF PERFORMANCE TRACKING
MCDONNELL, M., PBR DEEP DIVE WEBINAR: EXAMINING THE HAWAII EXPERIENCE, POWERPOINT, APRIL 2 2020.

PIMs principles

Agreeing on underlying principles to follow in designing PIMs can help align stakeholders on shared objectives. NERP agreed on these key principles to consider:

- PIMs should advance public policy goals, effectively drive new areas of utility performance, and incentivize nontraditional methods of operating.
- PIMs should be clearly defined, measurable, preferably using available data, and easily verified.
- PIMs should collectively comprise a financially meaningful portion of the utility's earning opportunities.
- No adopted PIM should duplicate a reward or penalty created by another PIM or other legal or regulatory mechanism.
- PIMs should reward outcomes, not inputs. In other words, the NCUC should avoid using expenditures as PIM metrics unless the desired outcome is increased spending.
- PIMs with metrics not controllable or minimally controllable by the utility should be upside only. A utility might prefer program-based PIMs, i.e., where incentives are awarded based on measurable actions, programs, and resources deployed or encouraged by the utility, over outcome-based PIMs given the risk that external factors may influence utility performance on the incentivized outcome (and therefore its compensation). Basing incentives on specific program results, e.g., kilowatt-hours saved through enrollment in an LED program, as opposed to outcomes, e.g., MWh saved system-wide, also makes symmetrical PIMs more of an option. However, a program-based PIM runs the risk of not achieving the desired outcome or decreasing the utility's flexibility to choose and amend the portfolio of programs and investments that best produces the desired outcomes.[18]

Once a PIM is established, it should be revisited on a regular basis to evaluate whether the selected metric, target, and incentive level are appropriate for achieving the outcome in question. If not, those parameters should

[18] For further discussion of activity-, outcome-, and program-based PIMs, see Goldenberg et al., *PIMs for Progress*, https://rmi.org/insight/pims-for-progress/.

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be adjusted to improve performance. The Minnesota PBR case study that accompanies this document includes a diagram showing this iterative process as it was envisioned in Minnesota.[19]

Listed below are a number of performance outcomes discussed by NERP. Under most of the outcomes is listed a preferred metric for achieving that outcome, along with several alternative metrics. NERP recommends:

- At the outset, track as many of the metrics described below as are deemed useful and cost-effective, and any others identified by any stakeholder process or by the NCUC. This data collection will help to determine which metric is actually most useful in measuring performance.
- Track the overall performance for each adopted PIM or tracked metric and, where applicable, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties.
- Establish a public dashboard for reporting performance on PIMs and tracked metrics.

Specific PIM outcomes recommended by NERP for NCUC consideration

Outcome: Peak demand reduction (or "Beneficial load-shaping" or "Aligning generation and load")
Preferred metrics: • Measurable load reduced/shifted away from peak based on measurement & verification from time-of-use (TOU) and other new rate designs (upside only, likely as shared savings) (program-based PIM) • Load factor for load net of variable renewable generation (upside only) (= average load not met by variable RE divided by peak load not met by variable RE) (Minnesota selected this as the metric for their PIM incentivizing "Cost-effective alignment of generation and load.")[20] • MW reduced from the utility's NCUC-accepted IRP peak demand forecast (for summer and winter peak) (upside only) (outcome-based PIM)
Alternative metrics: • enrollment (% of load or # of customers) in TOU rates or other advanced rates (symmetrical, likely as ROE adjustment) • MW demand response enrolled with TOU or other advanced rates (upside only, likely as ROE adjustment) • % of peak demand met by renewable energy (RE) or RE-charged storage and non-wires alternatives (upside only or, if symmetrical, set % target low and then progressively increase) • MW demand response utilized during critical peak periods identified for the purpose of utility tariffs using critical peak pricing (downside only with large deadband, i.e., penalty only for falling far short of target)
Notes: • This outcome serves two purposes: system efficiency and reducing need for new fossil fuel generation. • The preferred metrics listed above represent very different ways of looking at the problem. This area is ripe for innovation and requires further study and discussion before settling on an

[19] "Case Study: Minnesota Electricity Performance Based Rates," NERP, December 2020, page 5. Available here: https://deq.nc.gov/CEP-NERP

[20] Initial Comments of Fresh Energy, In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations, Docket E-002/CI-17-401, pp. 2-6, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D012CC6E-0000-C510-A1A9-501BF633BC7D}&documentTitle=201912-157970-01.

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approach. Even the definition of "peak" must be examined, as increased renewable generation in the future may lead to overall system peaks that are unproblematic because they are met by renewables, whereas the object of this PIM is to reduce demand that requires fossil fuel generation.

- Time-of-use rate design has been facilitated by the widespread installation of smart meters. Duke Energy is currently examining a suite of rate designs and DSM product bundles tailored to various customer segments that the utility believes can save customers money, drive overall system affordability, expand customer bill control, increase options related to clean energy and technology adoption, and create price signals that could offer significant peak demand reduction opportunities with minimal investment costs. Duke Energy believes that the same mechanism currently used for EE and DSM programs would be highly appropriate for measured and verified peak demand reduction and conservation from new rate designs. PIMs could be used to incentivize rate design that achieves desired NERP outcomes.

Outcome: Integration of utility-scale renewable energy (RE) & storage

Preferred metrics:

- Meeting interconnection review deadlines agreed on in queue reform (downside only)
- MW of RE interconnected over and above that required by law or policy (upside only)
- % MWh generation represented by RE

Alternative metrics:

- MW of utility-scale RE interconnected/yr
- MWh RE curtailment (symmetrical around a reasonable number)
- MWh of power from RE-charged utility-scale storage/yr (upside only)
- % RE capacity (MW) (tracked metric only)
- Avg. no. of days to interconnect utility-scale solar, below target(s) set forth in queue reform (upside only)

Outcome: Integration of DERs (RE/storage/non-wires alternatives)

Preferred metrics:

- 3-year rolling average of net metered projects connected (MW and # of projects) (upside only)

Alternative metrics:

- MW/MWh customer-sited storage in utility management programs
- # customers (and MW) participating in utility programs to promote customer-owned or customer-leased DER
- # customers (and MW) participating in utility programs to provide grid services (including RE, storage, smart thermostat, etc.)
- % of rooftop solar systems passing interconnection screens (upside only)

Notes:

- Revenue decoupling eliminates the throughput incentive but does not actively incentivize DER. Pairing this PIM with decoupling creates an incentive to increase DER.

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- Consideration should be given to New York's shared savings program for non-wires alternatives projects, in which the cost of the solution (regardless of ownership) is recoverable in a 10- to 20-year regulatory asset.[21]

Outcome: Low-income affordability

Preferred metric:

- % of low-income households, defined as those falling at or below 200% of the federal poverty level, that experience an annual electricity cost burden of 6% of gross household income or higher (upside only)

Alternative metrics:

- Total disconnections for nonpayment
- Usage per customer vs. historic rolling average, per class
- Average monthly bill
- % customers past due on their accounts
- # customers on fixed-bill programs

Notes:

- Why there is a need: In 2016, Duke Energy Carolinas had around 330,000 residential customers with household incomes ≤ 150% of the federal poverty level. They accounted for around 20% of DEC's total residential accounts. Those customers spent on average 10.5% of household income on energy (approximately 83% of which was for electricity and the rest for heating), compared to around 3% for DEC customers system-wide.[22]
- There is a need to ensure affordability for other customers as well. Municipal utilities would benefit from any outcome that reduces production costs and commercial and industrial (C&I) customers want to keep NC rates competitive with other Southeast states. Metrics may need to be developed for these other classes of customers and for residential customers who do not qualify as low-income. Some of the alternative metrics listed above might be useful for some of these customers.
- If a low-income rate pilot is adopted, it would help to inform the design of this PIM. Participants in the pilot would need to be selected randomly, and results would need to be reported, so that the energy burden of participating and non-participating households could be compared.
- A lower fixed charge could help low-income customers and might be possible with decoupling, which shifts more of the fixed costs into rates.

Outcome: Energy efficiency

Notes:

- Revenue decoupling eliminates the throughput incentive but does not actively incentivize energy efficiency (EE). Pairing this PIM with decoupling creates an incentive to increase EE.
- This was one of the more important outcomes for NERP participants, but no preferred metric was chosen because the NCUC would need to consider any new EE incentives in conjunction with the existing EE/DSM incentive, which is a PIM using a shared savings mechanism. It was

[21] Trabish, Herman K. "Tackling the perverse incentive: Utilities need new cost recovery mechanisms for new technologies," Utility Dive, March 16, 2018, https://www.utilitydive.com/news/tackling-the-perverse-incentive-utilities-need-new-cost-recovery-mechanism/518320/.

[22] Direct testimony of Rory McIlmoil in Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-7, Sub 1214, February 18, 2020, p. 35, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=11d407e8-1a85-487f-8548-ac2fa7cde2a5.

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amended in October 2020 under NCUC Dockets No. E-2, Sub 931 and E-7, Sub 1032, with changes to take effect in 2022.[23] • If North Carolina enacts revenue decoupling for electricity, the lost revenue adjustment mechanism (LRAM) associated with the existing EE/DSM incentive will no longer be needed and will need to be removed by the NCUC for the classes included in decoupling. Particular attention will need to be given to how this is done for the general service class, if small and medium general customers are included in decoupling but large general service customers are not. There also needs to be consideration given to small and medium general service accounts that can currently opt out of the LRAM mechanism and how that will be addressed with decoupling. The recommendations below could be considered at that time.
Possible amendments to existing incentive: • The current incentive imposes a penalty for incremental annual savings below 0.5% and offers a bonus above 1%. The NCUC order directed the EE/DSM Collaborative to study the impact of switching to a step approach in which the incentive is scaled up or down linearly above a minimum and maximum level (so that there is a possibility of some bonus between 0.5% and 1% and a possibility of additional bonus above 1%). If the study shows this approach to yield greater savings, such a step approach could be adopted. That incentive should likely be capped at a certain percentage of costs (e.g., Minnesota caps incentives at 30% of program costs).[24] • Consider advantages/disadvantages of shared savings mechanism vs. using as the core metric either kWh saved, Btu saved (to give credit for electrification) and/or greenhouse gas emissions saved. • Most states base their goals on savings in a given year (called incremental annual savings, that measure savings from measures installed in that year). Illinois and, more recently, Virginia measure total annual savings (savings persisting from previously installed measures and new measures installed in that year). Incremental annual savings is a simple place to start, but over time total annual savings may be a good framework, because it addresses the persistent effect of short-term measures such as low-flow showerheads or behavioral EE programs.
Additional metrics to track or incentivize: • Low-income participation in EE programs • % participation per class • # of C&I customers participating (upside only, with the utility rewarded for implementing programs that cause fewer C&I customers to opt out, but not penalized for failing to do so, since the outcome is minimally controllable by the utility)

Outcome: Carbon emissions reduction
Preferred metric: • Tons of CO2 equivalents reduced beyond what is required by law or policy (with cost-effectiveness test, upside only)
Alternative metrics: • Reduction in carbon intensity (tons carbon/MWh sold) (symmetrical) • Carbon price used in IRP scenarios ($/ton, tracked metric only)
Notes:

[23] Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d.

[24] "Case Study: Minnesota Electricity Performance Based Rates," NERP, December 2020, Available here: https://deq.nc.gov/CEP-NERP

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- Needs to be designed in accordance with any carbon policy resulting from the A-1 process. If no carbon reduction policy is achieved in the A-1 process, a PIM would be essential and could set benchmarks for reduction between now and 2050 that would incentivize meeting CEP carbon reduction goals.
- If this PIM were awarded on a dollar per ton basis, the NCUC could consult with the A-1 stakeholder group, who examined the effects of different carbon prices for future years.
- Consideration should be given to calculating and reporting (but likely not incentivizing) reduction in upstream methane emissions associated with gas burned in North Carolina, as these contribute significantly to climate change yet are not captured by the carbon accounting of the CEP. A PIM could eventually be appropriate if the state wishes to incentivize progress toward Duke Energy's goal, announced October 2020, of reducing upstream methane emissions in its natural gas distribution and power generation supply chains.[25]
- Any PIM in this area would need to be either based on North Carolina consumption with any incremental costs direct assigned to North Carolina customers or agreed to by regulators in both North Carolina and South Carolina.

Outcome: Electrification of transportation

Preferred metric:

- EV customers on TOU or managed charging (include home, workplace, fleets, and public charging) (upside only) OR
- MWh or % of EV charging load at low-cost hours (upside only)

Alternative metrics:

- Utilization of utility-owned public charging stations (upside only)
- Utility-owned charging in low-income areas (# or % chargers) (symmetrical)
- Customers enrolled in programs to encourage private charger installation (upside only)
- EV education (avoid rewarding $ inputs; maybe clicks on a web page; if expenditure metric, then downside only with spending cap)
- EV adoption
- CO2 avoided in transportation sector by electrification

Notes:

- Design in accordance with Duke Energy's EV pilot as approved November 2020.[26]
- Design depends on whether utility or others own charging infrastructure, since ROE on assets may be incentive enough.
- More research needed on how EVs can help with RE integration and how they can lead to reduced costs for all customers.
- Utility could use credits for off-peak charging but not put customers on TOU, or could use subscription pricing with managed charging. PIM should not constrain what method is used to promote off-peak EV charging.

Outcome: Equity in contracting

[25] "Duke Energy to reduce methane emissions in its natural gas business to net zero by 2030," https://www.duke-energy.com/_/media/pdfs/our-company/methane-reduction-fact-sheet.pdf?la=en.

[26] Order Approving Electric Transportation Pilot, In Part, Nov. 24, 2020, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=1c1665d0-d645-4293-82d8-ae9d7e672e3d.

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Preferred metrics: • % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are socially and economically disadvantaged as defined by 15 U.S.C. § 637 (tracked metric only) • % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are women (tracked metric only)
Notes: • There is also a desire to achieve equity in use of utility programs across income levels, but that needs more discussion.

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Outcome: Resilience
Preferred metrics: • Number of critical assets (see note below) without power for more than N hours in a given region (# of assets), N may be set as 0 hours or greater than the number of hours backup fuel is available • Critical asset energy demand not served (cumulative kW) • Critical asset time to recovery (average hrs)
Alternative metric: • Cumulative critical customer hours of outages (hrs)
Notes: • Recommended metrics revolve around impacts on critical community assets since that is the framework used in the PARSG (Planning an Affordable, Resilient and Sustainable Grid) project and in the state Resilience Plan. This approach is also being integrated into the NARUC-NASEO comprehensive system action plan that the NC delegation is considering. • Critical assets may include hospitals, fire stations, police stations, evacuation shelters, community food supply distribution centers, production facilities, military sites, etc. • Since resilience study is very much a work in progress in North Carolina, it is recommended that these initially be tracked metrics, with no incentive attached. • Efforts to develop resilience metrics are currently underway across organizations such as the DOE, FERC, EPRI and multiple state public utility commissions. The industry is lacking agreed-upon performance criteria for measuring resilience, as well as a formal industry or government initiative to develop consensus agreement.[27] As such, there are currently no standardized metrics to measure resilience efforts or to quantify the extent or likelihood of damage created by a catastrophic event. Resilience is addressed state-by-state, and oftentimes event-by-event. If different metrics, benchmarks, rewards or incentives are identified and developed for reliability and resilience,[28] there is a need to properly distinguish each, take into account the benefits for each, and differentiate how to separately determine the benefits, rewards and penalties for each.[29] • The metrics identified above are based on community impact driven resilience needs for critical infrastructure. It is based on current North Carolina state and local government led application of energy vulnerability and risk analysis framework that uses the Resilience Analysis Process (RAP) developed by the Sandia National Lab, which includes prioritization of grid-modernization initiatives that could achieve a desired set of resiliency goals for the community.

[27] IEEE Standards Association (2018) Grid Resilience and the NESC®.

[28] According to DOE, reliability refers to the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Resilience refers to the ability of a system or its components to adapt to changing conditions and to withstand and rapidly recover from disruptions.

[29] DOE (2017). See Key Findings at S-13: "There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics." https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

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PIMs needed in conjunction with a multi-year rate plan

A MYRP provides an incentive to cut costs. Therefore, these two PIMs should accompany a MYRP to guard against detrimental cost-cutting in the areas of reliability and customer service. If there is no MYRP, the metrics could be simply tracked and reported.

Outcome: Reliability
Preferred metric: • SAIDI (performance year-over-year, excluding extreme event days, downside only, feeder-by-feeder) (see note below)
Alternative metrics: • CEMI4 (customers experiencing more than 4 outages of 1 minute or more per year) • SAIFI • Miles of vegetation management (tracked metric only; see note below)
Notes: • The design should be downside only because the utilities' performance on reliability is already high. Providing a reward for further improvement might not provide a net benefit to customers (point of diminishing returns). • The feeder-by-feeder specification prevents selective maintenance. Central Maine Power experienced a drop in reliability on certain feeders when they had a reliability PIM in conjunction with a MYRP. • Tracking miles of vegetation management would give the NCUC a way to ascertain whether the MYRP was resulting in decreased maintenance. But many other factors affect that metric, so a financial penalty could unfairly punish the utility for matters beyond its control, and a financial reward could perversely incentivize unnecessary vegetation work.

Outcome: Customer service
Preferred metric: • Third-party customer satisfaction survey (e.g., JD Power score or Net Promoter score) (downside only)

Key issues requiring further discussion by the NCUC

As the NCUC considers PIM implementation, it will have to consider all of the parameters discussed above. The NCUC will need to review a utility's proposed metrics and PIMs and determine whether they incentivize the right outcomes, whether they employ the best metrics to measure each outcome, whether the targets are at the right level, and whether financial incentives for each metric are at the right level and appropriate to include. NERP hopes that the suggestions made above will help with that process.

Options for designing incentives

NERP did not discuss the form that PIMs should take. The four most common design options are listed here. Each design option has advantages and disadvantages, and some PIMs incorporate aspects of more than one design.

- **Shared savings or shared net benefits**
  Incentives can be based on shared net benefits or savings that allow a utility to keep a portion of the net benefits or savings that are created by the achievement of a performance target. Net benefits are

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calculated using the avoided costs that a utility would have incurred without the program minus the cost of the program itself.

- **Percentage adders based on spending**
  PIMs can allow a utility to earn a percentage return on their spending on particular programs, such as energy efficiency or DER initiatives, if they meet performance targets or program goals. This allows utilities to earn a return on expenses that would otherwise be a pass-through.
- **Fixed rewards or penalties**
  Utilities can earn or be penalized a fixed amount based on achievement of targets.
- **Adjustment to a utility's regulated ROE**
  PIMs can make a basis point adjustment of a utility's regulated ROE, which could more fundamentally impact utility investment decisions.

RECOMMENDED PROCESS FOR PBR DEVELOPMENT

PBR requires careful attention to key design details, especially for a comprehensive PBR approach as described here. NERP participants believe that enabling legislation will be beneficial to direct the next stage of PBR development, followed by a NCUC rulemaking process to adopt necessary rules for filing applications and criteria for evaluating them. Effective incentive regulation will also require ongoing monitoring and possible course corrections during a PBR regime (e.g., at the conclusion of a multi-year term, before advancing to the next term). This foretells the need for devoted attention and care from the NCUC and stakeholders to monitor utility performance and system outcomes, then make adjustments to guide utilities to continued improvement and value creation for customers.

Other states have applied a sequential process to develop and refine PBR, for example:

1. Articulate goals
2. Identify desired outcomes
3. Assess how current regulations meet or do not meet desired outcomes
4. Prioritize outcomes and identify PBR tools for further development
5. Design and iterate on PBR tools
6. Determine steps and requirements for implementation, including opportunity for evaluation

The NERP process has made substantial progress on the first four of these steps. A PBR process at the NCUC should seriously consider the conclusions reached by NERP, then follow the steps above, making sure to receive comment from as broad a group of stakeholders as possible, including any other relevant state agencies. Some specific steps that may be necessary are outlined below.

- First, the NCUC would lead a rulemaking process, to set up all of the filing requirements and procedures that any utility would need to follow to file a PBR application, including the criteria to be used by the NCUC in evaluating PBR applications. The NCUC should determine whether and in what form a stakeholder process should take place to gather input prior to a utility filing a PBR application.
- The utility would submit its PBR application as part of an initial base rate case. The utility would still file cost of service studies and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base. The utility's accompanying PBR application would include:
  - a decoupling plan including proposed adjustment and true-up mechanisms
  - a multi-year rate plan including the planned investments that the utility proposes to undertake during the term of a MYRP
  - an earnings sharing mechanism
  - a set of proposed PIMs, scorecard targets or reported metrics
- In addition to all the normal rate case activities, the NCUC would need to:
  - review and rule on the proposed decoupling and MYRP designs and proposed PIMs

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    - evaluate whether the planned investments are consistent with the goals of the CEP and the public interest and determine which of those planned investments would be allowed and what the allowed revenue increases would be over the term of the MYRP
    - for the customers included in decoupling, amend as needed the lost revenue adjustment mechanism (LRAM) that is part of the existing EE/DSM incentive, since decoupling adjusts revenue in a different manner
- Annually, the NCUC would review the results of the utility's operations during the prior year, including:
    - actual capital projects placed in service
    - utility earnings levels
    - utility sales and any adjustments needed due to a decoupling mechanism, including amounts to be refunded to or collected from customers based on the decoupling true-up mechanism and adjustments to rates going forward as a result of the mechanism
    - other utility revenue adjustments required by the adopted MYRP and ESM
    - utility performance against any adopted PIMs or tracked metrics to calculate penalties and incentives.

  After this review, the NCUC would approve the actual rates to be used in the subsequent year.
- NCUC rulemaking should outline what steps will be taken at the end of the initial MYRP period, including opportunities to add, delete, or adjust the approved set of PIMs to ensure they are capturing and driving desired utility performance.

Theoretical timeline

To help visualize how this process might unfold in North Carolina, NERP developed this entirely theoretical timeline:

- Legislation signed into law: June 2021
- NCUC issues rules for utility PBR applications: December 2021
- PBR application and base rate case filed by utility: July 2022
- NCUC proceeding to evaluate application: July 2022-March 2023
- NCUC order establishing PBR: March 2023
- First annual decoupling/MYRP true-up and PIMs review: March 2024

CONCLUSION

To summarize, NERP recommends that NCUC, subject to any guidance and timelines provided by legislation, begin as soon as possible a proceeding to develop rules under which a utility may file a comprehensive PBR application, including:

- Revenue decoupling excluding the large general service class to reduce the throughput incentive
- MYRP with an ESM and off-ramp to eliminate regulatory lag
- PIMs or tracked metrics to transition the utility revenue model toward achievement of regulatory goals, addressing the following outcomes: peak demand reduction, integration of DER and utility-scale RE and storage, low-income affordability, energy efficiency, carbon emissions, electrification of transportation, resilience, equity and – assuming a MYRP is adopted – reliability and customer service
- Provisions for annual or more frequent decoupling and MYRP true-ups and adjustment of PIM metrics, targets and incentive levels

Members of the NERP stakeholder group, in particular the PBR study group, stand willing to help the NCUC in its implementation of PBR, either in a stakeholder process or in any other way the NCUC deems appropriate.

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REFERENCES

There are many resources on PBR. Here are some that NERP found most useful.

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http://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

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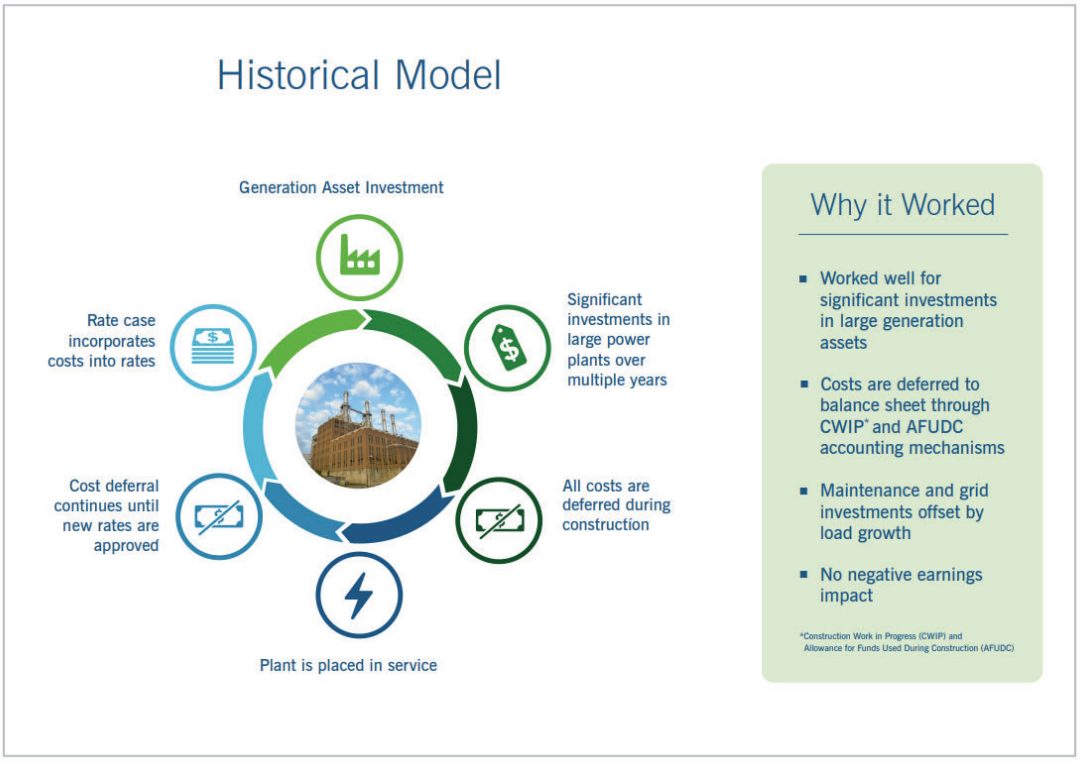
APPENDIX A

Solving for Regulatory Lag (Source: Duke Energy)

North Carolina Ratemaking and Recovery

The current regulatory system has served customers and utilities well for many decades. But today, utilities are shifting away from large-scale power plants toward modernizing the energy grid and adding more distributed energy. Therefore, a new model is needed to align the regulatory framework with investments in a 21st-century energy system.



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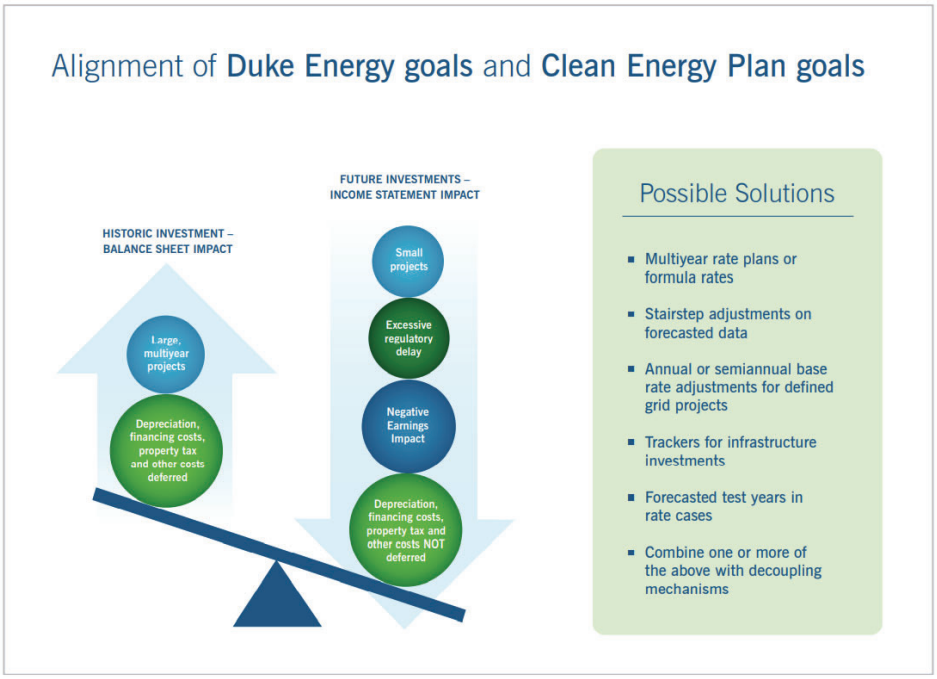

Modern Cost Recovery for Electric Utilities

Many other states have adopted one or more cost recovery mechanisms that enable higher levels of grid improvement investment:

- 24 states have multi-year rate plans or formula rates
- 23 states have trackers for grid/electric infrastructure investments
- 30 states have forward test years (full or partial)
- Only 7 states have none of these mechanisms – including North Carolina

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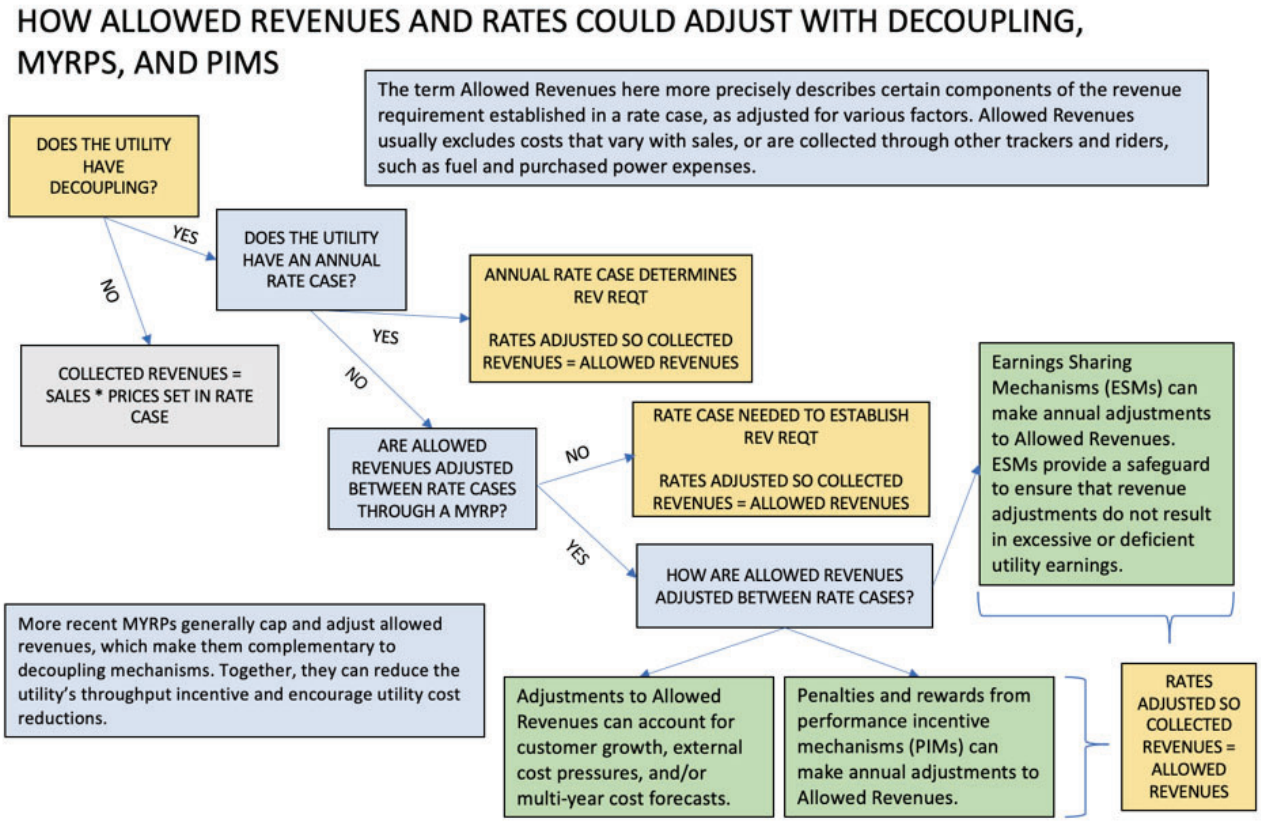
APPENDIX B

Flow Chart Diagram Depicting Potential Interactions and Coordination Between MYRP, Decoupling, and PIMs

Source: Rocky Mountain Institute

The following diagram depicts how several key PBR mechanisms operate together to adjust utility revenues and customer rates. It shows how revenue decoupling could operate with a MYRP that caps and adjusts a utility's revenues in the years between rate cases. Additional revenue adjustments resulting from performance incentives and an earnings sharing mechanism are also included to show how they might ultimately impact the revenues a utility is allowed to collect and the rates then charged to customers.



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PART I. AUTHORIZE RATES USING ALTERNATIVE MECHANISMS

Section 1.(a) Article 7 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"§ 62-133A. Performance-based rate methodology authorized.

(a) Declaration of Policy. - The General Assembly declares that utilities in the state have an important role to play in the transition to cleaner energy, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this policy. In combination with new technology and emerging opportunities for customers, this policy will spur transformational change in the utility industry. Given these changes, the legislature authorizes that the Utilities Commission's statutory grant of authority for rate making includes consideration and implementation of performance-based regulation (PBR) including: multiyear rate plans with earnings sharing mechanism, decoupling of utility revenues from energy sales, and performance incentive mechanisms to achieve just and reasonable rates and achieve its public interest objectives. The General Assembly also finds that the regulatory cost recovery mechanisms should better align the interests of customers and electric public utilities and that improvements should be made in the current rate making process to decrease the number of rate cases and reduce the regulatory lag that currently hinders certain capital investments, such as investments in the electric grid, storage or small scale renewables, and other technologies, necessary to support the clean energy transition. The PBR approach can be used to encourage: (a) alignment of electric utility incentives with customer and societal interests through regulatory mechanisms that motivate utilities to improve operations, increase program effectiveness, and better manage business expenses, (b) electric utility innovation in how it delivers service to customers; (c) electric utility investments to reduce carbon emissions, make the grid smarter, more resilient to adverse weather and to cyber and physical security threats, and capable of accommodating more renewable and distributed energy resources onto the system; (d) more efficient use of energy by customers; and (e) maintaining affordable and more predictable rates through annual rate adjustments spread over time. As such, the General Assembly declares that it is in the public interest to develop standards for performance-based regulation of electric utilities.

(b) Definitions. - For purposes of this section, the following definitions apply:

(1) “Performance-based regulation (PBR)” means an alternative rate making approach that includes (1) revenue decoupling; (2) multiyear rate plans with earnings sharing mechanism; and (3) performance incentive mechanisms.

(2) “Decoupling” means a ratemaking mechanism intended to break the link between a utility's revenue and the level of consumption of electricity by its customers.

(3) “Multi-year rate plan (MYRP)” means a ratemaking mechanism under which the Commission sets base rates based on a historic test year and revenue requirements necessary to cover new Commission-authorized costs that are expected to be incurred over a multi-year period through a plan which authorizes periodic changes in rates without a general rate application.

(4) “Earnings sharing mechanism” means a ratemaking mechanism that shares surplus or deficit earnings, or both, between utilities and customers.

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(5) "Performance incentive mechanism (PIM)" means a ratemaking mechanism that links electric utility revenue or earnings to electric utility performance in targeted areas consistent with customer and societal interests and regulatory and public policy goals and includes specific performance metrics and targets against which utility performance is measured.

(6) "Distributed Energy Resource (DER)" means a device or measure that produces electricity or reduces electricity consumption, and is connected to the electrical system, either 'behind the meter' on the customer's premises, or on the utility's primary distribution system. A DER can include, but is not limited to, energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.

(7) "Tracking metric" means a methodology for tracking and quantitatively measuring and monitoring outcomes or utility performance, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress toward a particular regulatory outcome.

(c) Authorization. - Notwithstanding the methods for fixing rates established under G.S. 62-133, the North Carolina Utilities Commission is authorized to utilize and approve PBR mechanisms proposed by electric public utilities and/or other stakeholders and intervenors, including, but not limited to, revenue decoupling, MYRP with an earnings sharing mechanism, and PIMs.

(d) Rulemaking. - Within six months of the effective date of this act, the Commission shall issue an order adopting rules consistent with this act. The Commission may initiate a stakeholder process to inform its rulemaking. The rules should prescribe the specific procedures and requirements that an electric utility must meet when filing a PBR Application, the criteria for evaluating such an Application, and the process for addressing deficiencies through a remedy that may consist of a collaborative process between stakeholders and the utility to cure any identified deficiency in the Utility's PBR Application in the event the Commission ultimately rejects a utility's PBR Application.

(e) Application. - A PBR Application shall be made in a general rate case proceeding initiated pursuant to G.S. 62-133, and must include details of: (1) a decoupling rate adjustment mechanism; (2) a MYRP if desired by the electric utility (including proposed revenue requirement and rates for each year of the MYRP or method for calculating such); and (3) PIMs (including but not limited to targeted areas of energy efficiency, peak demand reduction, and renewable energy and DERs). It may also include proposed tracking metrics with or without targets or benchmarks to measure utility achievement, and other PBR mechanisms to support the clean energy transition. The following additional requirements apply:

(1) MYRP may include annual rate adjustments based on projected investments, formulas, indexes, or a combination thereof. If the MYRP includes rate increases based on forecasted planned investments, the Commission shall require the electric utility to include in its PBR Application major planned investments over the plan period, the schedule for completion of those investments, and an explanation as to why the investments are in the public

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interest. If projected investments are not included in the MYRP rate adjustments until after the investments are in service, then the utility may request Commission approval to defer to a regulatory asset the incremental costs from the time the investment is placed in service until the costs are reflected in the MYRP rates.

(2) PIMs should be clearly defined, measurable with a defined performance metric, and reasonably within the utility's control. The incremental costs required to achieve a PIM shall, upon approval by the Commission, either be included in rates under a MYRP or deferred to a regulatory asset until such time as the costs can be incorporated into the utility's rates.

(f) When reviewing a PBR application, the Commission may approve PIMs proposed by the electric utility as part of a PBR application including the following:

(1) Rewards based on the sharing of savings achieved by meeting or exceeding a specific performance target;

(2) Rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet specific performance targets;

(3) Fixed financial rewards to encourage achievement of specific performance targets, or fixed financial penalties for failure to achieve such targets; and

(4) Any other incentives or financial penalties that the Commission determines to be appropriate.

(g) The Commission shall approve the PBR Application by an electric utility only upon a finding by the Commission that such mechanisms are just and reasonable, and are in the public interest pursuant to G.S. 62-2(a). In reviewing any such Application under this section, the Commission may consider whether the Application, as proposed: (i) assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric utility and to the customer, (ii) reasonably assures the continuation of safe and reliable electric service, (iii) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock," to customers, (iv) is otherwise consistent with the public interest, (v) encourages peak load reduction or efficient use of the system, (v) encourages utility-scale renewable energy and storage, (vi) encourages DERs, (vii) reduces low-income energy burdens, (viii) encourages energy efficiency, (ix) encourages carbon reductions, (x) encourages beneficial electrification, including electric vehicles, (xi) supports equity in contracting, (xii) promotes resilience and security, and (ix) maintains adequate levels of reliability and customer service.

(h) Decision. - Upon receiving a PBR Application by an electric utility that incorporates PBR mechanisms as listed in (e), the Commission, after notice and an opportunity for interested parties to be heard, is authorized to issue an order within the time frames set forth in G.S. 62-134, approving or rejecting the utility's PBR Application; in addition to its order ruling on the electric utility's request to adjust base rates under G.S. 62-133. If the Commission rejects the PBR Application, it must provide an explanation of the deficiency and an opportunity for the utility to refile or for the utility and the stakeholders to collaborate to cure the identified deficiency and refile.

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(i) Plan Period. - Any PBR Application approved pursuant to this section shall remain in effect for a plan period of not more than 60 months. Prior to the end of the PBR plan period, if the utility has not filed a petition for a subsequent PBR plan, the Commission shall initiate a proceeding to examine options for renewing or revising the PBR mechanisms.

(j) Review. - At any time prior to conclusion of a PBR plan period, the Commission, with good cause and upon its own motion, has the discretion to examine the reasonableness of the electric utility's rates under the plan, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust rates or PIMs as necessary. In addition, nothing in a PBR proposal shall inhibit or take away from the Commission's authority to grant deferrals for extraordinary costs in between rate cases.

(k) Utility Reporting. - For purposes of measuring an electric utility's earnings under a PBR Application approved under this section, the electric utility shall make an annual filing that sets forth the electric utility's earned return on equity, the electric utility's revenue requirement trued up with the actual electric utility revenue, the amount of revenue adjustment in terms of customer refund or surcharge, and the adjustments reflecting rewards or penalties provided for in performance-based plans approved by the Commission.

(l) Nothing in this section shall be construed to (i) limit or abrogate the existing rate-making authority of the Commission or (ii) invalidate or void any rates approved by the Commission prior to the effective date of this section. In all respects, the alternative ratemaking mechanisms, designs, plans or settlements shall operate independently, and be considered separately, from riders or other cost recovery mechanisms otherwise allowed by law, unless otherwise incorporated into such plan.

(m) Commission Report. - No later than April 1 of each year, the Commission shall submit a report on the activities taken by the Commission to implement, and by electric power suppliers to comply with, the requirements of this section to the Governor, the Environmental Review Commission, and the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources. The report shall include any public comments received regarding environmental impacts (including but not limited to air, water and waste emission levels) of the implementation of the requirements of this section. In developing the report, the Commission shall consult with the Department of Environmental Quality.

SECTION 2.(b) The Commission shall adopt rules as required by G.S. 62-133A(g), as enacted by Section 2(b) of this act.

PART II. EFFECTIVE DATE

SECTION 1. Part I of this act is effective when it becomes law and applies to any rate-making mechanisms filed by an electric utility on or after the date that rules adopted pursuant to G.S. 62-133A(g), as enacted by Section 2(a) of this act, become effective.

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NERP CASE STUDY

NATURAL GAS DECOUPLING IN NORTH CAROLINA

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

BACKGROUND AND JUSTIFICATION FOR NATURAL GAS DECOUPLING IN NORTH CAROLINA

Historically, there have been large fluctuations in the cost of natural gas. During a rate case in 2002, natural gas had a benchmark cost[1] of $2.75 per dekatherm. When the natural gas distribution companies (Piedmont Natural Gas Company, Inc., North Carolina Natural Gas, and Eastern North Carolina Natural Gas Company, ["Company"]), filed their joint rate case[2] in 2005, their benchmark cost was $7.00 per dekatherm. Subsequently, the benchmark increased to $11.00 per dekatherm by the time that the Notice of Decision from the North Carolina Utilities Commission (NCUC) was made. The higher prices caused customers to decrease use, insulate homes, and purchase efficient appliances. Both the increase in gas cost and decreases in customer use resulted in the natural gas companies not recovering their approved cost margin. All these practices adversely impacted the Company's recovery of its approved margin.

The Company's weather-normalized usage per residential customer declined an average of 2% per year and was expected to continue in future years. Usage was declining due to customer adoption of more efficient appliances to lower natural gas bills.

The Company's volumetric rate structure created a disincentive for the Company to implement energy efficiency and conservation initiatives for its customers (i.e. was not environmentally or economically sustainable).

The historical ratemaking process did not ensure that the Company fully recovered the cost of gas delivered to its customers. Gas costs (meeting the definition of North Carolina General Statute (NCGS) 62-133.4) were trued-up based on the amount billed to customers, instead of the amount "actually" collected. Therefore, the cost of the gas delivered to customers' who did *not* pay their bills (referred to as the uncollectables[3] expense) could not be recovered by the Company.

IMPLEMENTATION TIMELINE AND HISTORY

- On February 28, 2005, the Company gave notice of their intent to file a rate case.

[1] The benchmark reflects the price that market participants use to write contracts and achieve full transparency around transactions. The benchmark is the variable cost in rate design.

[2] See dockets G-9, Sub 499; G-21, Sub 461; and G-44, Sub 15

[3] Accounts that have virtually no chance of being paid.

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- On April 1, 2005, the Company filed a petition for: 1) consolidation of their revenues, rate bases, schedules and expenses; 2) a general increase in their rates and charges; and 3) approval of depreciation rates. This facilitated the transition from a three-company operation into a single integrated Company.
- On August 31, 2005, the Company, the NCUC Public Staff, Carolina Utilities Customers Association (CUCA), and the federal Department of Defense (DOD) filed a Stipulation to further request the merger. In addition, the Stipulation requested the implementation of a test program for decoupling termed the "Customer Utilization Tracker" (CUT) in conjunction with an energy conservation program.
- On September 2, 2005, the Office of the Attorney General filed its Statement of Position regarding the Stipulation objecting to the implementation of: (1) the CUT; and (2) the recovery mechanism for the gas cost portion of uncollectable expenses. The Attorney General recommended the CUT be implemented for only a trial period.
- On September 28, 2005, the NCUC approved the Joint Proposed Order of Stipulating Parties. This document contained the proposed program details and rate design (which is described in more detail later in this case study).
- On November 3, 2005, the NCUC issued the final order to approve a pilot decoupling mechanism (the CUT) for a period of no more than three years.
- The NCUC specified that there was statutory authority to authorize true-up mechanisms for:
- natural gas (NCGS 62-133.4); and
- electricity (NCGS 62-133.2).[4]
- Despite their determination that statutory authority existed to authorize decoupling mechanisms, the NCUC asked the legislature to enact a law that allowed NCUC to adopt a natural gas decoupling rate mechanism to avoid future lawsuits associated with rate cases.
- On July 18, 2007, Session Law 2007-227 House Bill 1086 authorized customer usage tracking rate adjustment mechanisms for natural gas local distribution company rates.[5] This bill formally codified the CUT rate adjustment mechanism for natural gas local distribution company rates in NCGS 62-133.7.[6]
- On March 31, 2008, the Company filed for approval to permanently extend the decoupling mechanism in its general rate case[7]. The decoupling mechanism's name was proposed to be changed from the CUT to the Margin Decoupling Tracker (MDT). In this general rate case, the Company also asked for a rate increase for a fair rate of return on invested capital. This was due to: 1) significant new investments to grow and maintain the gas distribution systems to benefit current and future customers; 2) significant changes in the Company's costs and capital structure; and 3) significant declines in average per-customer usage from the assumed usage levels in existing base rates.
- On August 25, 2008, the Company, Public Staff, CUCA, DOD, and Texican filed a Stipulation of agreement.[8] The Stipulation contained the proposed rate changes and request for permanently extending the decoupling mechanism's pilot program into the MDT.
- On October 24, 2008, NCUC issued an order that allowed the Company to permanently incorporate the MDT and increase rates by a total of $15.7 million (1.5% of the Company's total operating revenues). The NCUC specified that increases to the Company's revenues during the pilot program did not indicate any flaw in the decoupling mechanism. However, it indicated that the Company was continuing to experience system growth (53,000 new customers since 2005) which produced additional revenues. One advantage of the MDT is that any growth that adds revenues at a rate higher than that approved by the NCUC actually lowers rates for existing customers.
- The NCUC relied on NCGS 62-133.7 for authority to permanently implement the MDT in 2008. The MDT's foundational design elements remained consistent with the CUT. A couple notable revisions in 2008 were: (1) an increase in the rates (1.5% of the Company's total operating revenues) so the Company could earn a fair rate of return; and (2) an increased annual expenditure of $1.275 million on conservation and energy efficiency programs.

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[4] North Carolina case law for historical precedents included the following:
State ex rel. Utilities Comm. v. CF Industries, Inc., 299 NC 504 (1980);
- CF Industries, 299 NC at 505-6 and 508;
- CF Industries, 299 NC at 507-9; and

State ex rel. Utilities Comm. v. Public Service Company, 35 NCApp 156 (1978);
- Public Service Company, 35 NCApp at 156-7;

State ex rel. Utilities Comm. v. Edmisten, 291 NC 327 (1976); and
State ex rel. Utilities Comm. v. N.C. Natural Gas Corp., 323 NC 630, 631 (1989)

[5] House Bill 1086 (Session Law 2007-227): https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2007-2008/SL2007-227.pdf

[6] The Session Law's text states: *§ 62-133.7. Customer usage tracking rate adjustment mechanisms for natural gas local distribution company rates. In setting rates for a natural gas local distribution company in a general rate case proceeding under G.S. 62-133, the Commission may adopt, implement, modify, or eliminate a rate adjustment mechanism for one or more of the company's rate schedules, excluding industrial rate schedules, to track and true-up variations in average per customer usage from levels approved in the general rate case proceeding. The Commission may adopt a rate adjustment mechanism only upon a finding by the Commission that the mechanism is appropriate to track and true-up variations in average per customer usage by rate schedule from levels adopted in the general rate case proceeding and that the mechanism is in the public interest.*

[7] See Docket G-9, Sub 550 for material related to adopting a permanent extension of the decoupling mechanism.

[8] See the Stipulation for details on the rate design for the MDT, including Net operating income, Rate Base and Overall Return "Exhibit A"; Rate design "Exhibit B"; Fixed gas cost allocations "Exhibit C"; Margin decoupling mechanism factors "Exhibit D"; Tariffs "Exhibit E"; Service regulations "Exhibit F"; Cost of gas "Exhibit G"; Impact of stipulated rate increase by customer class "Exhibit H"

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DESIGN ELEMENTS OF THE 2005 DECOUPLING PILOT

The mechanism decouples recovery of the approved margin from customer usage. The piloted decoupling mechanism ensured that the Company collects 100% of its gas costs, prospectively. The residential and commercial sectors were included in the mechanism. The industrial sector was not included since its usage patterns and tariffs are vastly different than the residential and commercial sectors.[9]

The CUT rate adjustments were made semi-annually. These adjustments were not made in dollar amounts (like the Weather Normalization Adjustment that had been in effect prior to the adoption of the decoupling pilot). Rather, the CUT adjustments were to rates (prices) paid by customers.

The decoupling mechanism promoted conservation efforts by the Company and customers. In addition, it allowed customers to realize savings in their total gas bill associated with lower gas consumption. In the order authorizing the CUT mechanism, the NCUC ordered the Company to contribute $500,000 per year toward conservation programs and work with the Attorney General and Public Staff to develop appropriate and effective conservation programs. Such programs were to be submitted for approval by the NCUC within 45 days of the final order's issuance and were subject to an annual effectiveness review.

The decoupling mechanism used a straight fixed variable rate structure where the fixed costs would be recovered through a fixed monthly charge to customers.

Multiple compliance reports were required, including:

- annual conservation reports;
- conservation effectiveness reports;
- semi-annual true ups; and
- monthly account adjustment reports.

SOME ARGUMENTS FOR AND AGAINST THE 2005 DECOUPLING PILOT

Opponents argued that decoupling expanded the definition of "gas cost" beyond what was allowed by NCGS 62-133.4. Specifically, that the Company's write offs for nonpayment of bills were not *"occasioned by changes in the cost of natural gas supply and transportation"* in accordance with NCGS 62-133.4(a). They also stated that the affected portion of uncollectible accounts expense was not a cost *"related to the purchase and transportation of natural gas to the Company's system"* consistent with NCGS 62-133.4(e) or Rule R1-17(k).

The counterargument, which was ultimately persuasive to the Commission, is that the Company must pay suppliers for all the gas sold to customers, regardless of the number of customers who fail to pay their bills. The gas cost portion of uncollectables represents *"costs related to the purchase and transportation of natural gas"* which are under NCGS 62-133.4. Prior to decoupling, customers were at risk that the pro forma[10] uncollectible accounts expense could be higher than the actual expense of the Company. The CUT mechanism eliminates this risk and ensures that the Company will collect 100 percent of gas costs compared to a "proxy amount."

Opponents argued that rate adjustment mechanisms or "true up procedures" such as the CUT were traditionally prohibited in the State since it constitutes a retroactive ratemaking.[11] The Commission disagreed, stating that the prohibition is based upon the theory of ratemaking contained in G.S. 62-133, and it therefore does not apply to true up mechanisms specifically authorized by statute. The Commission stated that the prohibition on retroactive ratemaking applies to "fixed general" rates but not "formula rates" such as the CUT.

[9] See the Stipulation of the Parties for details on the pilot program's rate design, including: Net operating income, Rate Base and Overall Return "Exhibit A"; Depreciation rates "Exhibit B"; Rate design "Exhibit C"; Fixed gas cost allocations "Exhibit D"; Customer utilization tracker factors "Exhibit E"; Tariffs "Exhibit F"; Service regulations "Exhibit G"; Cost of gas "Exhibit H"; Temporary rate increments/decrements "Exhibit I"

[10] A report of the company's earnings that excludes unusual or nonrecurring transactions.

[11] The Attorney General cited case law. But the NCUC did not agree that the case law and stated, *"The prohibition against retroactive ratemaking was discussed in State ex rel. Utilities Comm. v. Edmisten, 291 NC 451, at 468-470 (1977). The prohibition is based upon the theory of ratemaking contained in G.S. 62-133, and it therefore does not apply to true up mechanisms specifically authorized by statute such as G.S 62-133.2 or G.S. 62-133.4. The prohibition applies to "fixed general" rates and is not violated when a formula that has been approved as part of a utility's rate structure is used to true-up an estimated rate. 156 (1978). The Commission believed that the CUT is not a "fixed general" rate but rather should be approved as a formula rate*

Opponents argued that decoupling shifts the risk of fluctuations in gas costs from the Company to the ratepayer,[12] and that decoupling penalizes customer conservation by eventually causing rate increases to allow the companies to recover costs.[13] The Commission strongly disagreed with both of these arguments.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:
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Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

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[12] NCUC Order Granting Partial Rate Increase and Requiring Conservation Initiative (p. 17). https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=0ab8a646-9837-4c85-b650-77638a534073
[13] NCUC Order Granting Partial Rate Increase and Requiring Conservation Initiative (p. 21 and 23). https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=0ab8a646-9837-4c85-b650-77638a534073

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NERP CASE STUDY

MINNESOTA ELECTRICITY PERFORMANCE BASED RATES

The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

INTRODUCTION

Due to the complexity of Minnesota's lengthy performance-based regulation (PBR) process, this case study summarizes the basic aspects of PBR in the state. It then focuses on data that may indicate some of the outcomes from the implementation of these efforts over the last few years.

BACKGROUND

In 2007, Minnesota passed the Next Generation Energy Act (NGEA).[1] This law requires investor-owned utilities (IOUs) to do the following;

1. Reduce energy sales,
2. Spend a minimum percentage of annual operating revenues on energy efficiency, demand-side management and renewable energy starting in 2010, and
3. Incorporate a **shared savings financial incentive** model for energy efficiency.

It also required the Minnesota Public Utilities Commission (MPUC) to establish criteria and standards for **decoupling energy sales from revenues** to mitigate the impact of these energy savings goals on public utilities.

There were other factors driving electricity rate reform in the state including declining sales growth, minimal increases in customer base, and the need for infrastructure investments. The decline in sales growth, from 2% annual growth rate in the 1990s to the current annual growth rate of 0.5%, is shown in Figure 1.

[1] Minnesota Statutes, Section 216B.2412, Next Generation Energy Act, 2007.

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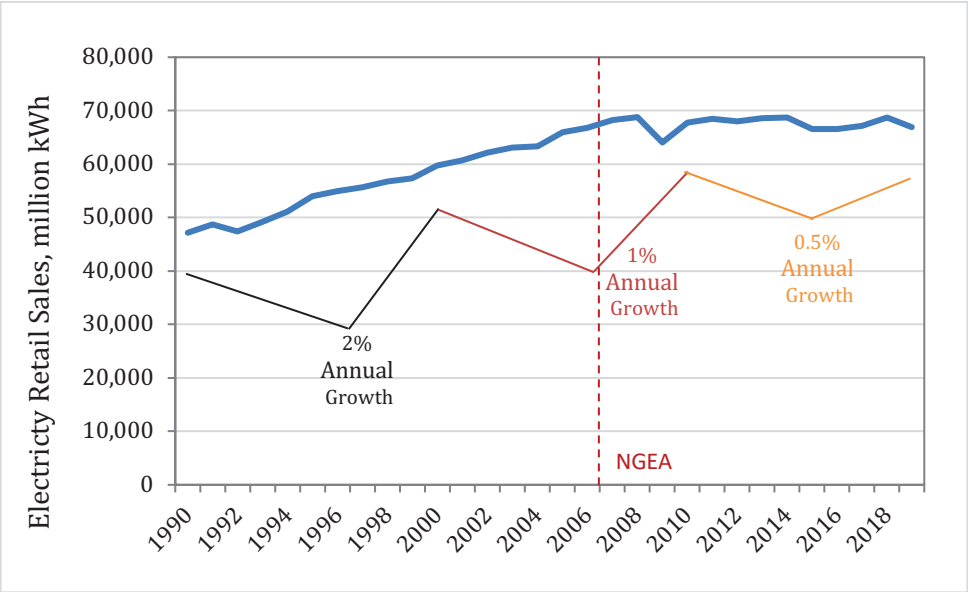
FIGURE 1: MINNESOTA RETAIL SALES OF ELECTRICITY SINCE 1990



SOURCE: ENERGY INFORMATION ADMINISTRATION (EIA) AND NC DEPARTMENT OF ENVIRONMENTAL QUALITY (NC DEQ)

Another factor in Minnesota's PBR history is Xcel Energy initiating an enterprise-wide carbon reduction plan in December of 2018.[2] Xcel was one of the first utilities in the country to develop such a plan, with a goal of 80% reduction by 2030 and 100% carbon free by 2050. As of 2019, Xcel Energy reduced its enterprise-wide carbon by 44% from 2005 levels. During 2019, Xcel Energy generated 35% of all electricity in Minnesota with fossil fuel, with 21% of that generation coming from coal and the remainder coming from natural gas.

FIGURE 2: XCEL ENERGY'S 2018 CARBON REDUCTION GOAL

SOURCE: XCEL ENERGY

While Minnesota began its path toward performance-based rates through the NGEA in 2007, it is still being developed and implemented today. This ongoing effort consists of the following components;

- Multiyear rate plan (MRP),
- Revenue decoupling mechanism ("decoupling"),
- Performance incentive mechanisms, including metrics and incentives, and
- Shared savings mechanism ("shared savings").

AUTHORITY AND ENABLING STRUCTURES FOR PBR IN MINNESOTA

Multiyear Rate Plans

[2] Xcel Energy Clean Energy Transition, https://www.xcelenergy.com/environment/carbon_reduction_plan

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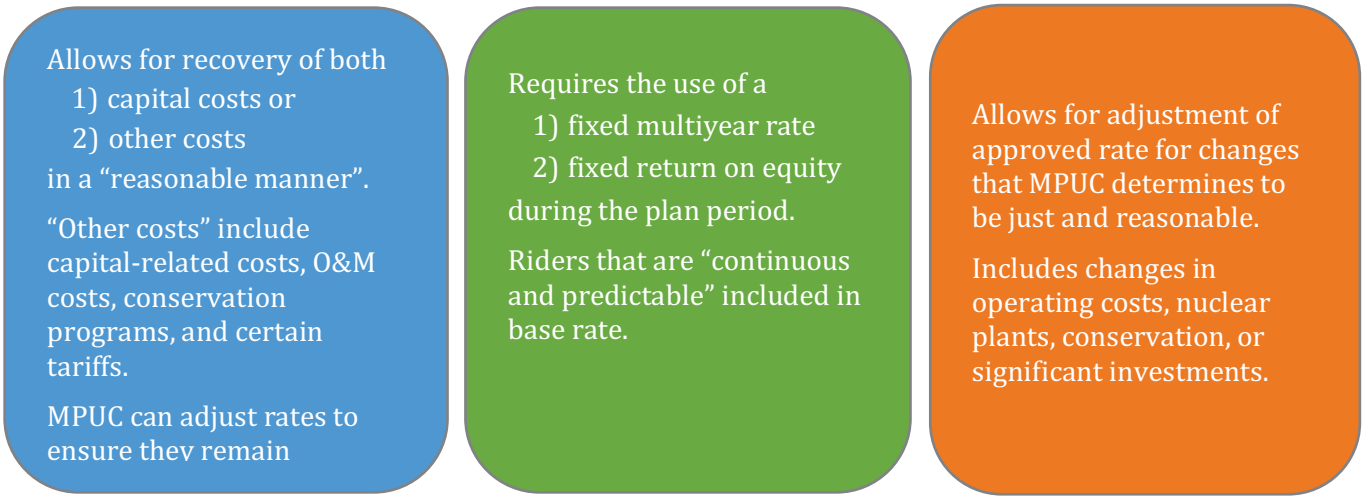
In 2011, the Minnesota Legislature enacted Minn. Stat. § 216B.16, subd. 19 Multiyear Rate Plan, authorizing the MPUC to approve multiyear rate plans (MRP) up to 3 years in length for regulated utilities and to establish the terms, conditions, and procedures for plans.[3] On June 17, 2013, the MPUC issued a final order on the terms and conditions for MRPs.[4] This order specified that rates charged under any MRP should be based on the utility's reasonable and prudent costs of service. It also specified that a MRP could be designed to recover costs for "specific, clearly identified capital projects and, as appropriate, non-capital costs". It also declined the use of formula rates and required a fixed rate for the plan period; however, rate adjustments pertaining to the cost of energy, emissions controls, conservation improvement, and specific tariffs were allowed. Lastly, the PUC decided that the authorized rate for return on equity would be fixed during the plan period based on the rate used in the general rate case. While the MPUC did not include an "off ramp" for the MRP, it did specify that the MPUC could adjust rates while a plan was in effect to ensure that the rates remain reasonable.

In June 13, 2015, the Minnesota Legislature modified the statute to allow a MRP to extend up to 5 years. The legislation also gave the MPUC the authority to require utilities proposing MRPs "to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies."

The components of the MRP, as established in the MPUC's 2013 decision, are presented in Figure 3.

FIGURE 3: COMPONENTS OF MINNESOTA MULTIYEAR RATE PLANS BASED ON MPUC 2013 ORDER



Decoupling Rate Mechanisms

In 2007, the Minnesota Legislature enacted Minn. Stat. § 216B.2412 as part of the NEGA requiring the MPUC to establish criteria and standards for decoupling of energy sales from revenues. The legislation specified that decoupling include the following;

- Ensure the criteria and standards do not adversely affect utility ratepayers,
- Consider energy efficiency, weather, cost of capital, and other factors,
- Assess the merits of decoupling to promote energy efficiency and conservation, and
- Implement a voluntary pilot program to determine if decoupling achieves energy savings.

On June 19, 2009, the Commission issued its Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling in Docket E, G-999/CI-08-132. The details of the decoupling mechanism not included in this case study in lieu of the detailed discussion of decoupling as implemented by Xcel Energy in Section 3 below.

Performance Incentive Mechanisms

[3] Minnesota Statutes, Section 216B.16, subd. 19 Multiyear rate plan
[4] Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, Issued June 17, 2013, Docket No. E,G-999/M-12-587

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As discussed above, performance incentive mechanisms (PIMs) were authorized by the MRP Legislation in 2015. This legislation gives the MPUC authority to require IOUs to submit PIMs with MRP and to establish the PIMs. The statute also authorized the Commission "to initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan."

An important first step in the development of PIMs began with a multi-year stakeholder process called the "e21 Initiative". This process began in 2014 and was facilitated by Great Plains Institute and Center for Energy and Environment. The goal was to advance a decarbonized, customer-centric, and technologically modern electric system in Minnesota. The reports issued by the e21 Initiative documents the stakeholder findings and results.[5]

The e21 Initiative developed the foundation for PIMs. Over 100 performance metric topics were discussed by stakeholders. Key aspects included:

- Specifying goals for PIMs,
- Determining data points to measure in order to evaluate utility performance,
- Limiting the specific number of metrics and prioritizing implementation of certain metrics,
- Developing concrete procedures for calculating, verifying, and reporting metrics, and
- Specifying metrics should measure outcomes, not deployment of technologies or programs.

The MPUC opened a docket to identify and develop performance metrics and, potentially, incentives in 2017 in response to Xcel Energy submitting a set of performance metrics in their general rate case filed in 2015. On January 8, 2019, the MPUC issued the Order Establishing Performance-Incentive Mechanism Process.[6] The order initiated a PIM development process, which included discussions and workshops with stakeholders over a 9-month period. The order established a "goals-outcomes-metrics process" as an effective method to gather stakeholder input and develop performance metrics. Figure 4, presented on the following page, summarizes the 7-step process laid out by the MPU. The MPUC completed Steps 1 and 2 via the January 8, 2019 order.

On September 18, 2019, the MPUC issued an order establishing performance metrics.[7] In this order, Xcel Energy was directed to work with stakeholders to develop 1) methods to calculate, verify, and report metrics, and 2) a reporting schedule, which are Steps 3 and Step 4 of the PIMs process.

[5] See https://e21initiative.org/ for a full description of the e21 Initiative including its work products and reports.
[6] MPUC Order Establishing Performance-Incentive Mechanism Process, Issued January 8, 2019, Docket No. E-002/CI-17-401.
[7] MPUC Order Establishing Performance Metrics, Issued September 18, 2019, Docket No. E-002/Ci-17-401.

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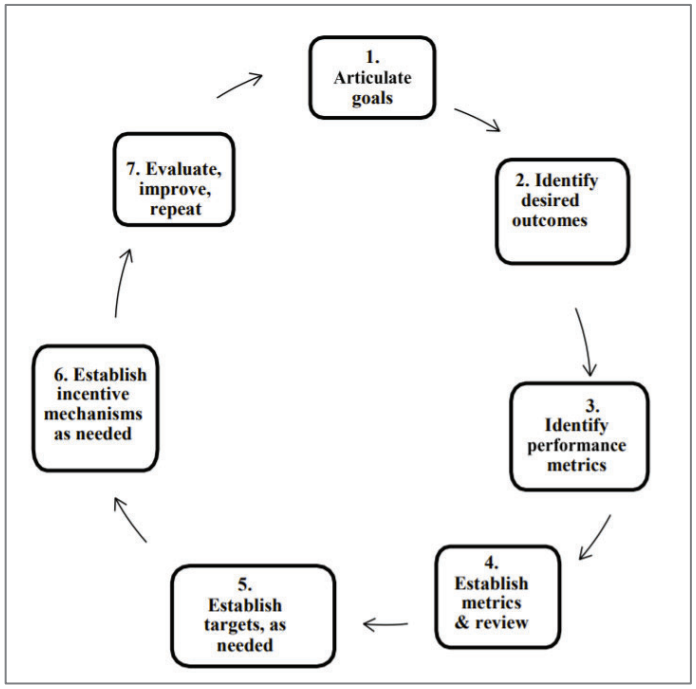
FIGURE 4: MINNESOTA PUBLIC UTILITIES COMMISSION PROCESS TO ESTABLISH PIMS



SOURCE: MPUC

Shared Savings Mechanism

Minnesota has had a shared benefit incentive for energy efficiency in place since 1999 called Conservation Improvement Program (CIP). For gas and electric utilities, the percent of net benefits awarded increases as a utility achieves a higher level of energy savings measured as a percentage of retail sales. The current Shared Savings goals for the electricity sector are listed in Figure 5.[8]

FIGURE 5: SHARED SAVINGS MECHANISM FOR ELECTRICITY SECTOR INVESTOR OWNED UTILITIES

Shared Savings Mechanism

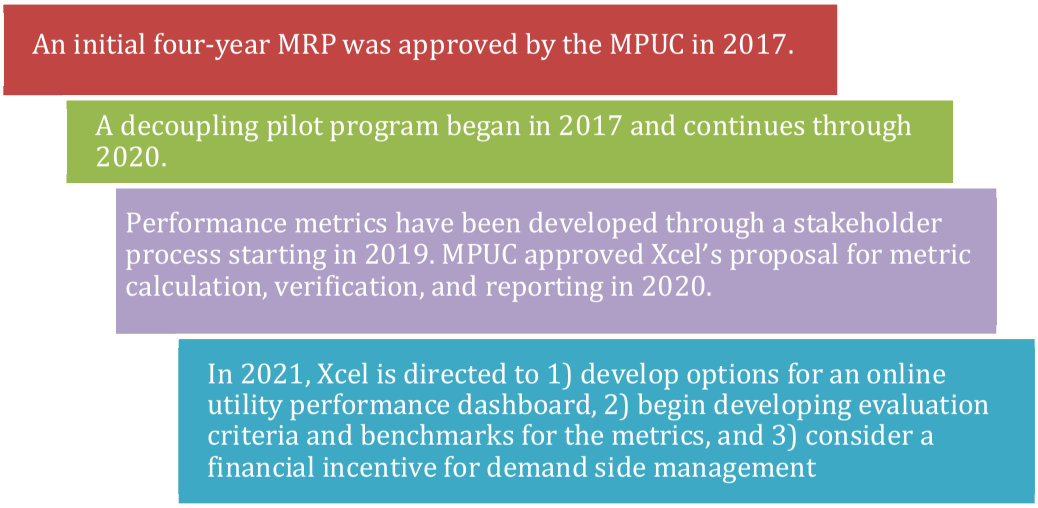
- The energy savings threshold is set at 1.0% of retail sales.
- For each energy savings increase of 0.1% of retail sales beyond the threshold, the net benefits awarded increase by 0.75%
- There is a net benefits cap, after reaching a 10% energy savings level, equal to 1.7% of retail sales.
- The incentive levels are capped at 30% of a utility's Conservation Improvement Program (CIP) expenditures.

XCEL ENERGY IMPLEMENTATION OF PBR

The only electric utility currently pursuing PBR in Minnesota is Xcel Energy. For Xcel Energy, this process started with filing for a MRP in a general rate case in March of 2015. This filing set off a series of events for Xcel Energy to implement the PBR framework laid out by both legislation and MPUC orders. The events are summarized in Figure 6.

[8] See Minn. Stat.§ 216B.241, subd. l (c) and MPUC Docket No. E,G-999/CI-08-133

FIGURE 6. SUMMARY OF XCEL ENERGY'S PBR PROCESS



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Xcel Energy MRP

Xcel Energy filed a petition on November 2, 2015 requesting a 3-year MRP that allowed revenue increases supporting the utility's proposed cost of service.[9] The parties could not come to an agreement and the matter was referred to the Office of Administrative Hearings for contested case proceedings. On August 16, 2016, the majority of the parties to the rate case submitted a "Stipulation of Settlement" regarding the utility's MRP. The settlement set out the following design details for the MRP: [10]

- The revenue requirement, which entailed annual revenue increases over four years with a cumulative increase of 6.1%.
- The use of weather normalized sales data to set the base rates, and
- A one-year extension of the MRP to 2019.

Not all parties agreed to the settlement, therefore interim rates were set while additional proceedings were conducted to resolve the remaining issues. One of the issues was the return on equity (ROE) of 9.2%, which the Office of the Attorney General argued should be lower, on the order of 7% to 8%. On June 12, 2017, the MPUC issued an order documenting the decisions on Xcel's 2017 MRP based on both the settlement and the additional proceedings.[11] The MPUC kept the ROE from the settlement, adjusted Xcel's annual revenue requirements downward substantially, which resulted in rate increases that were less than inflation and significantly less than what Xcel proposed. Additional requirements on Xcel included;

- Prohibiting the filing of another rate case or seeking new riders during the MRP,
- Adopting a **one-way, aggregate, capital-spending true-up** where Xcel can refund money if its spending is under the budget but cannot increase rates if over the budget, and
- Requiring an annual capital projects true-up compliance report providing **granular project data and spending** for approximately 1,800 projects.

The MPUC found that a capital-projects true-up would provide ratepayers with significant protection against over budgeting of capital-spending. In addition, it would be beneficial for regulatory-review purposes to have Xcel Energy file project-level information on capital spending rather than overall spending in a given year. Figure 7 presents the basic structure of Xcel Energy's MRP for 2017 through 2019 stipulated in the MPUC Order.

[9] Xcel Energy, Application for Authority to Increase Electric Rates, Filed November 2, 2015, Docket No. E002/GR-15-826.
[10] Xcel Energy Filing, Stipulation of Settlement Authority to Increase Electric Rates Northern States Power Company, Filed August 16, 2016, OAH Docket No. 19-2500-33074 and MPUC Docket No. E002/GR-15-826.
[11] MPUC, Findings of Fact, Conclusions, and Order, June 12, 2017, Docket No. E-002/GR-15-826

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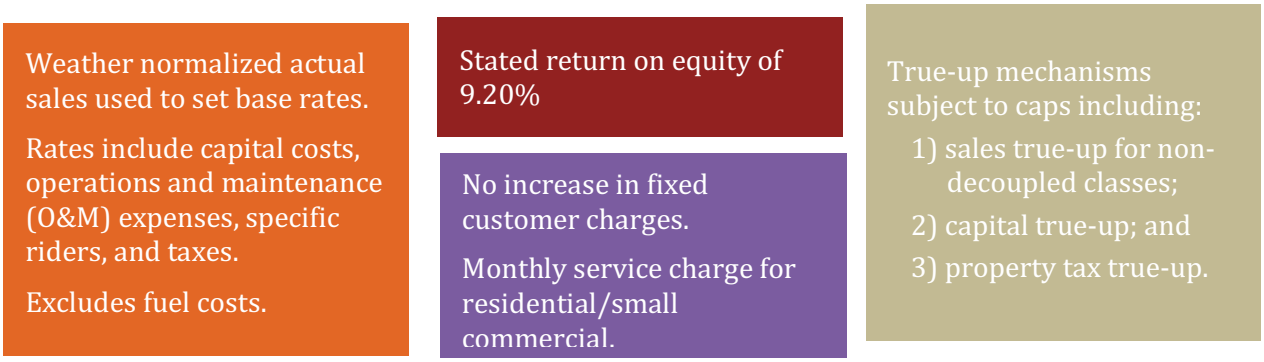
FIGURE 7: STRUCTURE OF XCEL'S MRP



Adjustments are also allowed for customer classes under full decoupling. See below.

With the ending of the initial MRP in 2019, Xcel Energy filed a new MRP rate case with a request for a 3-year rate increase totaling 15.2% with the MPUC on November 1, 2019. This rate increase included an interim rate increase of 4% for all customer classes, $466 million in new revenue, and an increase in return on equity to 10.3%. Given the decoupling pilot was expected to end in 2019, the rate plan also proposed a new decoupling mechanism that would apply to all customer classes.

On the same date, Xcel Energy filed a petition to extend the current MRP plan through 2020 using three true-up mechanisms for sales revenues, capital costs, and property taxes, explaining that if the MPUC approved the petition they would withdraw its rate case filing and not file another one until November 2020.

On Dec. 12, 2019 the MPUC approved Xcel Energy's Petition for Approval of True-Up Mechanism and Xcel withdrew its 2020 rate proposal.[12] As a result, electric base rates remained unchanged in 2020. In addition, the sales true-up mechanism (which was functionally equivalent to decoupling for customer classes not included in the 2017 pilot) was extended to all customer classes at that time.

Similar to 2019, Xcel Energy has recently requested Commission approval for 2021 true-ups that would allow the utility to leave base rates for 2021 unchanged.[13] In the event this petition is not approved, Xcel also has filed a three-year MRP starting in 2021 that would increase revenues a total of 19.7%.[14] Xcel has justified this rate increase on increased investments in renewable energy resources, investments in other core and supporting infrastructure, and declining sales. The utility also has proposed interim rate increases for 2021 and 2022 as the MPUC considers the MRP request.

Xcel Energy Decoupling Pilot

Xcel Energy filed its proposal for a decoupling pilot project in 2015 with its MRP discussed above. On May 8, 2015, the MPUC issued its Findings of Fact, Conclusions of Law, and Order authorizing the pilot.[15] However, the "Stipulation of Settlement" submitted on August 16, 2016 modified the decoupling pilot program by 1) extending the program by one year and 2) requiring the use of partial decoupling (i.e., sales true-up based on weather-normalized data) for commercial and industrial customers. Xcel Energy began the four-year decoupling pilot program starting in 2017.

Xcel Energy's revenue adjustment mechanism is revenue per customer. This means that as the revenue requirement is adjusted according to the pre-agreed schedule in the multi-year rate plan, the decoupling mechanism also adjusts required revenue to reflect the increase or decrease in the number of customers within Xcel's service territory. The decoupling mechanism also has incentives for energy conservation.

Figure 8 presents the decoupling design elements of Xcel Energy's decoupling pilot. It focuses on the customer classes, for which the largest share of fixed costs is recovered through volumetric rates – residential (space heating and non-space heating), and small commercial and industrial (non-demand). It also includes partial decoupling that was added via the Stipulation of

[12] MPUC Order Approving Xcel Energy's Petition for Approval of True-Up Mechanism, Issued March. 13, 2020, Docket E002/M-19-688.
[13] MPUC Docket No. E-002/M-20-743
[14] MPUC, Application for a Proposed Increase in Electric Rates, November 2, 2020, Docket No.E-002/GR-20-723
[15] MPUC Order Findings of Fact, Conclusions, And Order, Issued May 8, 2015, Docket E-002/GR-13-868.

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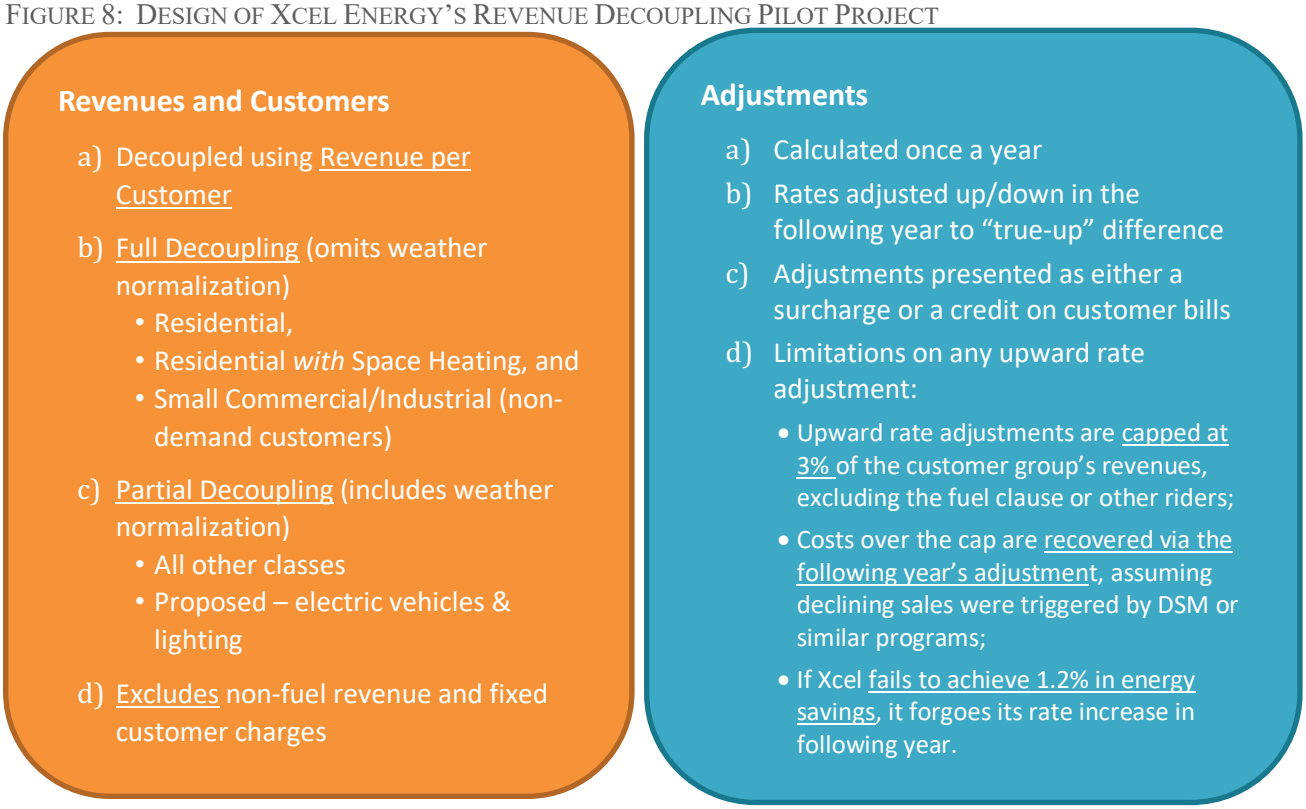
Settlement in 2016 order discussed above that began in 2019. Xcel Energy filed decoupling annual reports to the MPUC, which will be discussed in the Outcomes section of this study.

FIGURE 8: DESIGN OF XCEL ENERGY'S REVENUE DECOUPLING PILOT PROJECT



Xcel Energy Performance Mechanisms

When the Commission approved Xcel's MRP in 2017, a docket was opened to focus on PIM development. On September 18, 2019, the MPUC issued an order establishing performance metrics.[16] The order also directed Xcel to work with stakeholders to develop methods to calculate, verify, and report metrics, and a reporting schedule by October 31, 2019.

On October 31, 2019, Xcel Energy submitted its report on performance metrics and proposed both outcomes and metrics to track starting in 2020, with reporting starting in 2021.[17] Over 30 performance metrics were proposed measuring the outcomes listed below. The specific metrics are listed in Appendix A of this report.

- affordability
- reliability
- customer service quality
- environmental performance
- cost effective alignment of generation and load
- workforce and community development impact

The MPUC took comments on the proposal and on April 16, 2020 issued an order accepting Xcel's proposed methodology and reporting schedules, with several modifications.[18] Annual reporting of performance metrics is required and Xcel was directed to "explore and develop" an online utility performance dashboard.[19] Xcel Energy was directed to continue to work on Steps 3 and 4 of the PIMs process—metric identification and review—and begin work on Steps 4 through 6, which includes the following processes;

- developing a demand response financial incentive via a stakeholder process,

[16] MPUC Order Establishing Performance Metrics, Issued September 18, 2019, Docket No. E-002/CI-17-401

[17] Xcel Energy Filing, Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives, Docket No. E002/CI-17-401

[18] MPUC Order Establishing Methodologies and Reporting Schedules, Issued April 16, 2020, Docket No. E-002/CI-17-401

[19] Annual reporting is required by April 30 of each year.

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- developing evaluation criteria and benchmarks, and
- using a standardized method to ensure consistency with other utility reporting.

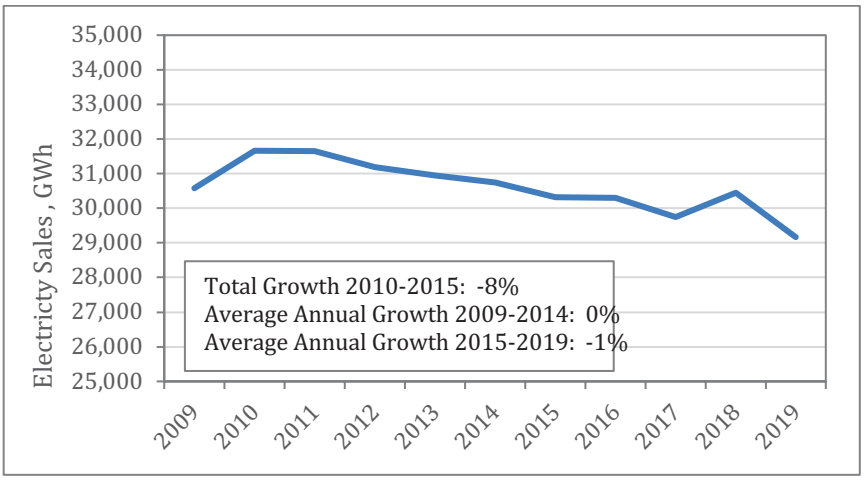
OUTCOMES FROM PBR FOR MINNESOTA AND XCEL ENERGY

Minnesota is still in the early stages of implementing PBR. Xcel Energy's MRP and the revenue decoupling mechanism pilot program have run over the last 4 years are ending in 2020. Xcel will begin measuring and reporting on performance metrics in 2021.

The following three graphs show how some key data for Xcel Energy has changed in the last 10 years.[20] The graphs have imbedded tables with the data broken down to show the 1) total growth over the 10-year period from 2009 to 2019 and 2) and the average annual growth broken into two 5-year periods to show the potential impact of Xcel Energy's implementation of PBR.

Figure 9 presents electricity sales data in GWh. This graph indicates Xcel Energy's sales have dropped by 8% over the last 10 years. Note there was an increase in 2018 due to more extreme weather in that year. The average annual growth rate in the first half was 0% while it was -1% in the second period, indicating that sales are decreasing slightly more rapidly in the second half of the period. This could be influenced by a number of things, including decoupling and the ongoing Shared Savings program for energy efficiency. Nonetheless, it indicates that these programs appear to be effective in Minnesota.

FIGURE 9: XCEL ENERGY - ELECTRICITY SALES IN GWH FROM 2009 TO 2019



Despite the decrease in sales, Xcel Energy's customer base is growing by 7% over the same 10-year period as shown in Figure 10. This amounts to a 1% average annual growth rate over both 5-years periods. Declining load growth creates a problem for traditional ratemaking approaches where increasing sales lead to increasing revenues. Xcel Energy needed to break that relationship to allow the company to recover sufficient revenues to meet its costs associated with additional customers while promoting higher levels of energy efficiency.

[20] Energy Information Administration, Form EIA-861M Monthly Electric Power Industry Report, 2019 Final Data, https://www.eia.gov/electricity/data/eia861m/

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FIGURE 10: XCEL ENERGY – NUMBER OF CUSTOMERS IN THOUSANDS FROM 2009 TO 2019

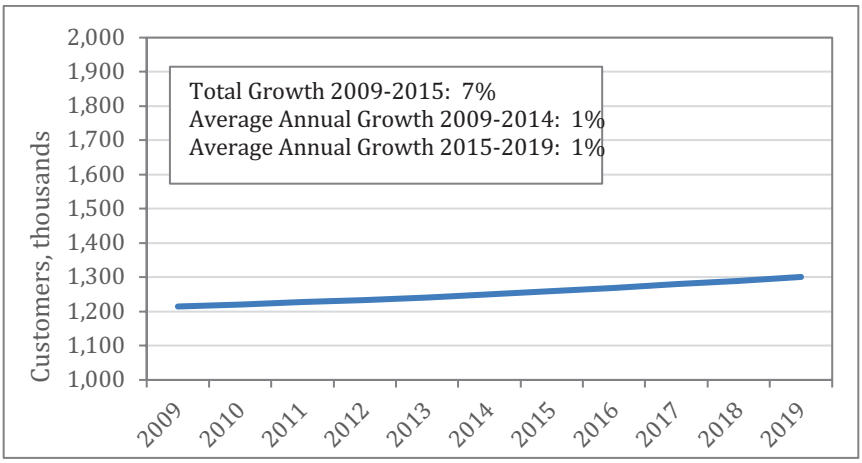
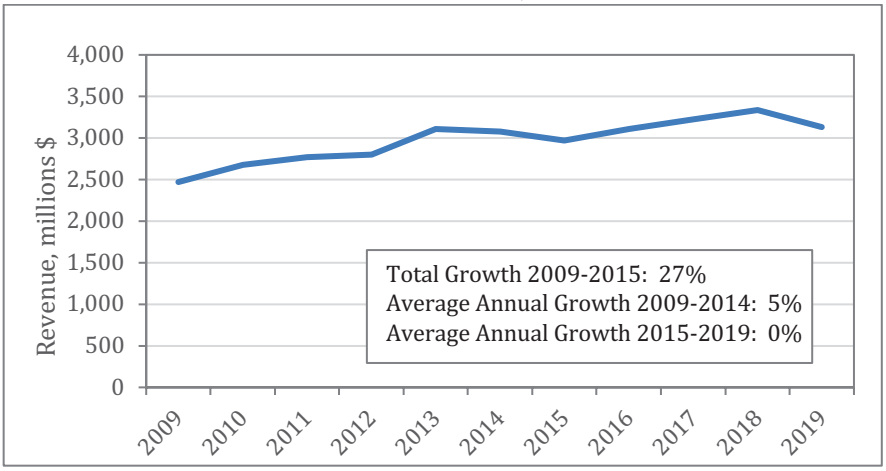


Figure 11 presents Xcel Energy's revenues over the past 10 years. Revenues have increased by 27% since 2009. However, the average annual growth in the first 5-year period was 5% while the average annual growth was 0% in the last five years. This indicates revenues are stable and increasing at a slower rate under the multiyear rate plan.

FIGURE 11: XCEL ENERGY – REVENUES IN $ MILLION FROM 2009 TO 2019



One of the benefits of a MRP is improvements in the utility's credit rating due to more stable revenues. Xcel Energy's Minnesota utility earned an "A" for its **Long-Term Issuer Default Rating (IDR)** by Fitch Ratings in October of 2020.[21] Fitch Ratings cited stable revenues for the utility due to the following:

- a constructive regulatory environment in Minnesota,
- its operation under a four-year rate plan, and
- the use of various cost-recovery riders.

This is in contrast to Xcel Energy's Southwestern Public Service Company (SPS) located in a more "challenging" regulatory environment, which earned it a rating of "BBB".

Metrics show that Xcel Energy has been financially stable over the last few years, even during the time of the pandemic. In a recent presentation to investors, Xcel showed that is has a return on equity (ROE) of 10.97% at the holding-company level and

[21] Source: Fitch Affirms Ratings on Xcel Energy & Subs; Outlook Stable, Issued October 1, 2020, accessed at https://www.fitchratings.com/research/corporate-finance/fitch-affirms-ratings-on-xcel-energy-subs-outlook-table-01-10-2020.

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9.53% for its Minnesota operating company. Xcel Energy also reported that earnings per share for their Minnesota operating company were up 10% in the first nine months of 2020 compared to the same period in 2019.[22]

As stated previously, Xcel Energy submitted a report to the MPUC on its decoupling pilot program starting in 2017 for the 2016 calendar year. A summary of the calculations and the data contained in the reports for 2016 through 2019 is presented below and in Table 1.[23, 24, 25, 26]

For Xcel's Minnesota customers, a cooler than normal summer results in less electricity sales and a warmer summer results in higher sales. Therefore, over-collection of revenues is associated with summers that are warmer the baseline year and generally results in a refund to customers under decoupling. Under-collection of revenues is associated with cooler summers and generally results in a surcharge to customers.

During 2016, a warmer than normal winter resulted in an over collection of revenues for residential and small commercial and industrial customers, however, it also resulted in an under-collection of revenue for the residential space heating class as a result of the higher electricity intensity of this class, causing a surcharge. In total, the amount refunded to customers was $1.80 million.

The years 2017 and 2019 had cooler than normal summers compared to the baseline year, resulting in total revenue shortfalls and surcharges of $27.50 million and $31.20 million. In both years, the revenue surcharge was capped at 3%, thereby reducing the surcharge by $0.4 million in 2017 and $4.20 million in 2019. These amounts are carried over into the next year. This leaves a surcharge of $27.10 million for 2017 and $27.00 million for 2019 that was added to customer bills. For 2019, Xcel Energy attributes its large decrease in sales in part to energy efficiency realized from the Conservation Improvement Program (CIP).

The year 2018 was cooler than normal and resulted in an under-collection of revenue and a total refund of $13.80 million. It is noted that surcharges for 2017 and 2019 were significantly higher (+65% difference) than the refund in 2018.

[22] Comments of the Office of Attorney General, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, filed November 12, 2020, Docket No. E-002/GR-20-723.
[23] Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission February 2, 2018, https://www.leg.mn.gov/docs/2018/mandated/180155.pdf
[24] Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission February 2019, https://www.leg.mn.gov/docs/2019/mandated/190367.pdf
[25] Decoupling and Decoupling Pilot Programs: Report to the Legislature, Minnesota Public Utilities Commission January 15, 2020, https://www.leg.mn.gov/docs/2020/mandated/200074.pdf
[26] Xcel Energy, 2019 Annual Report: Electric Revenue Decoupling Pilot Program, filed January 31, 2020, Docket No. E002/M-20-

TABLE 1: XCEL ESTIMATED REVENUE DECOUPLING ADJUSTMENT, BY CLASS

	Class	Total Decoupling Surcharge/(Refund) $ millions	Carry Over Balance[2]	Estimated Surcharge Cap $ millions	Class Impact,[3] in $ millions	Average Monthly Customer Surcharge/ (Refund)	Decoupling Rate ($/kWh) April-March	Year
2016[1]	Residential	($2.60)		$0.00	($2.60)			Credit
	Residential w/Space Heat	$1.10		$0.90	$0.90			Surcharge
	Small C&I (Non-Demand)	($0.10)		$0.00	($0.10)			Credit
	Total	($1.60)		$0.90	**($1.80)**			
2017	Residential	$25.00		$26.20	$25.00	$1.87	$0.0031	Surcharge
	Residential w/Space Heat	$1.30		$0.90	$0.90	$2.19	$0.0024	Surcharge
	Small C&I (Non-Demand)	$1.10		$2.50	$1.10	$1.06	$0.0012	Surcharge
	Total	$27.50			**$27.10**			
2018	Residential	($12.50)	($0.70)	$26.20	($13.20)	($0.98)	($0.0016)	Credit
	Residential w/Space Heat	($0.30)	($0.10)	$0.90	($0.40)	($0.99)	($0.0011)	Credit
	Small C&I (Non-Demand)	($0.20)	0	$2.50	($0.20)	($0.18)	($0.0002)	Credit
	Total	($13.00)			**($13.80)**			
2019	Residential	$28.20	($1.20)	$25.60	$24.40	$1.79	$0.0031	Surcharge
	Residential w/Space Heat	$0.30	($0.10)	$0.90	$0.20	$0.45	$0.0005	Surcharge
	Small C&I (Non-Demand)	$2.80	($0.10)	$2.50	$2.40	$2.31	$0.0028	Surcharge
	Total	$31.20			**$27.00**			

1 In 2016, adjustments were not applied to monthly bills
2 Carry-over (over/under-collection) balance from decoupling deferrals.
3 Includes the total decoupling credit and carry-over balance.

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The main purpose of the decoupling pilot program was to determine if decoupling created incentives for higher energy conservation and energy efficiency than the traditional system. Table 2 presents Xcel Energy's savings due to Minnesota's Conservation Improvement Program (CIP) both before and after decoupling.[27] Based on the table, the average first-year energy savings under decoupling was 113 GWh, or 23% higher than without decoupling. This indicates that Xcel Energy's decoupling pilot program was largely successful at significantly reducing electricity sales beyond what CIP required while earning revenue.

TABLE 2. XCEL ENERGY CIP ELECTRIC SAVINGS (2013-2019)

	Year	First-year Energy Savings (GWh)	Retail Sales (GWh)28	Energy Savings Percent of Retail Sales (GWh)
Without Decoupling	2013	495	28,987	1.71%
	2014	481	28,987	1.66%
	2015	497	28,987	1.72%
	Average	**491**	**28,987**	**1.69%**
With Decoupling	2016	547	28,987	1.89%
	2017	658	28,948	2.27%
	2018	680	28,948	2.35%
	2019	530	28,948	1.83%
	Average	**604**	**28,957**	**2.09%**

[27] Xcel Energy, 2019 Annual Report: Electric Revenue Decoupling Pilot Program, filed January 31, 2020, Docket No. E002/M-20-

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APPENDIX A

List of PIMs Proposed in 2020 by Xcel Energy for Tracking

Outcome	Metric
Affordability	Rates based on total revenue y customer class and aggregate
	Average monthly bills
	Total residential disconnets for non-payment
Reliability	System Average Interruption Duration Index (SAIDI)
	System Average Interruption Frequency Index (SAIFI)
	Customer Average Interruption Duration Index (CAIDI)
	Customers Experiencing Long Interruption Duration (CELID)
	Customers Experiencing Multiple Interruptions (CEMI)
	Average Service Availability Index (ASAI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Momentary Average Interruption Frequency Index (MAIFI)
	Power Quality
	Equity – Reliability by geography, income, or other benchmarks
Customer Service Quality	Initial customer satisfaction metrics
	Commission-approved utility-specific survey
	Subscription to third-party customer satisfaction metrics
	Call center response time
	Billing invoice accuracy
	Number of customer complaints
	Equity metric – customer service quality by geography, income or other relevant benchmarks
Environmental Performance	Total carbon emissions by utility-owned facilities/PPAs and all sources
	Carbon intensity (ton/MWh) by utility-owned facilities/PPAs and all sources
	Total criteria pollutant emissions
	Criteria pollutant emission intensity
	CO2 emissions avoided by electrification of transportation
	CO2 emissions avoided by electrification of buildings, agriculture, and other sectors
Cost Effective Alignment of Generation and Load	Demand response, including capacity available and amount called
	Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns
	Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation
	Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events
	Metrics that measure the effectiveness and success of above items individually and in aggregate

SOURCE: XCEL ENERGY FILING, PROPOSED METRIC METHODOLOGY AND PROCESS SCHEDULE ON PERFORMANCE METRICS AND INCENTIVES, DOCKET NO. E002/CI-17-401

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This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

LEARN MORE

Contact NERP PBR Study Group Leads:
Sally Robertson, NC WARN, sally@ncwarn.org
Laura Bateman, Duke Energy, laura.bateman@duke-energy.com

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

Corrected
Council Rebuttal Exhibit 1
Docket No. E-7, Sub 1276

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Metro Program - Analysis of 2023 DE Plaza Project Build New option in comparison to 2016 Renovation 526CH option

This cash view analysis encompasses the total project costs and the ongoing O&M.

		Current DE Plaza		526 Renovation Option				
	Project Cost	**2023 - $709 million**		**2016 - $289 million**				
A.	**Adjustments to Project Costs**	**Total approved Funding minus exclusions**		**Year**	**Total Project Cost with escalation**	**Factor**		**Difference**
		This adjustment indicates the costs that were excluded from the DEC-NC rate base			This adjustment acknowledges actual inflation in the rise in prices for construction labor and materials			
	Starting point	**$ 709,000,000**		**2016**	**$ 289,173,591**			Post-Covid, the scope and costs would have been updated and re-considered for the renovation option.
		$ (8,414,123)	Art	**2017**	$ 301,897,229	4.4%		Source: National Construction Inflation Report 2022 published 5-08-2022
		$ (14,653,076)	L10/L38	**2018**	$ 317,897,782	5.3%		Source: National Construction Inflation Report 2022 published 5-08-2022 Assumes 5 yr Renov project would have started in 2019 like DE Plaza
				2019	$ 331,769,782	4.8%		Source: National Construction Inflation Report 2022 published 5-08-2022
				2020	$ 337,549,782	2.5%		Source: National Construction Inflation Report 2022 published 5-08-2022
				2021	$ 353,155,782	9.0%		Source: National Construction Inflation Report 2022 published 5-08-2022
				2022	$ 368,068,182	12.9%		Source: Construction Analytics 1-18-2023
				2023	$ 370,842,582	4.8%		Based on current year projections; Source: Construction Analytics 1-18-2023
A -	**Total Project Cost**	**$ 685,932,801**			**$ 370,842,582**		**$ -**	**$ (315,090,219)**
B.	**Contingency % for Level of Estimate**	**Guaranteed Maximum Price with General Contractors**	**3.5%**		**Based on Rough Order of Magnitude Estimate**	**23.6%**		Owner contingency expected to cover unforeseen circumstances such as structural issues, additional move costs, swing space lease cost (team noted that the $25 rate was too low)
		Guaranteed Maximum Price contract provided cost certainty and the current cost projection is informed by actuals, not preliminary estimates only			Owner EMV contingency should have been higher due to the uncertainty and unknowns for an aging structure built in 1970's. General Contractors and Owner contingency are normally equivalent at this level of estimate.		Based the ~24% on the amount of contingency that the General Contractors (construction & interiors) included in their project estimates	Source: DPR Pre-Construction Lead advised 10% contractor contingency and 10% owners contingency for a Class 3 Estimate. Both the GC and the owner contingency should be relatively the same percentage. For a Class 5 (less precise) estimate like the renovation project option in 2016, the contingency should be higher. Furthermore, any structural issues that were discovered during a Renovation project would come from the Owner contingency (not the GC contingency).
b.1	**EMV Initial Contingency (Owner)**	no change			$ 16,599,845	7.5%		Initial estimate included in 2016 Renovation Total Project Cost
b.2	**Revised EMV Contingency**				$ 52,082,431	23.6%		Total Project Cost minus contingency = $220,348,746 ($272,573,746 - $52,225,000) multiplied by contingency %
b.3	**Incremental EMV Contingency**				$ 35,482,586			Incremental calculation = b.2 minus b.1
b.4	**Revised for price escalation**				$ 43,296,756	22.0%		adjusted for price escalation
B -	**Total A cost plus Incremental**	**$ 685,932,801**			**$ 414,139,338**			**$ (271,793,463)**
C.	**Facility Portfolio O&M Costs**	**Portfolio Cumulative as of Year 2052**			**Portfolio Cumulative as of Year 2052**		**Portfolio Facility Cost Differential**	Includes lease rent, passthrough of some landlord operating expenditures (e.g., utilities, routine repairs), facility maintenance costs (e.g., cleaning, roads and grounds, security & life safety, mail room services, repairs & maintenance).
	Selected the year 2052 since it is the lease end date for the DE Plaza.	Portfolio includes the DE Plaza long-term and shows the divestment of leased and owned facilities by 2026.			Portfolio strategy included 526 Church, 400 S. Tryon, Piedmont Town Center, and Duke Energy Center. This analysis recognizes a divestment of 400ST post Covid.			To accommodate the headcount, the Renovation option would have required more facilities than 526 S. Church Street even post-Covid.
c.1	36 Years of Portfolio Facility Cost for term of DE Plaza Lease	$ 1,707,744,288			$ 2,067,361,973		$ 359,617,685	Refer to Price Escalation tables for detailed cost projections by facility. For Renovation, this analysis recognizes that we may have divested of 400ST post-Covid due to Hybrid working.
C -	**Total B Cost plus Facility costs**	**$ 2,393,677,089**			**$ 2,481,501,312**			**$ 87,824,222**
D.	**Revenue**							
	36 years of Parking Revenue	$ (20,165,760)	36		$ (11,896,560)	36		parking revenue straight-lined not adjusted for escalation; DE Plaza = based on May 2023 actual revenue, then increased by 20% // 526 S. Church based on 1Q 2023 actuals // excludes Retail Sub-lease revenue and Tenant Upfit costs since shareholder expense
D -	**Total C Cost minus Parking Revenue**	**$ 2,373,511,329**			**$ 2,469,604,752**			**$ 96,093,422**
	TOTAL PROJECT COST	**$ 2,373,511,329**			**$ 2,469,604,752**			**$ 96,093,422** **view includes total project costs and ongoing O&M offset by revenue**

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Charlotte office market report

Q2 2023

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Charlotte office market trends

$171m

Investment volume 2023 YTD

Q2 marked the second consecutive quarter in a relatively dormant office sales environment. The combination of higher interest rates and ongoing structural changes in the office market has slowed investment volume both in Charlotte and across the United States. Year to date, Charlotte's office sales volume is 3.8 times lower than the average total sales during the first half of each subsequent year dating back to 2012. Look to see increased activity in distressed sales among incoming loan maturities.

22.8%

Total availability

Direct and sublease availability in the Charlotte Metro has increased 110 bps from last quarter, jumping from 21.7% in Q1. The flight in available space can be largely attributed to the amount of sublease space coming to market, now accounting for 16.3% of available SF, well above the 10-year average of 10.2%

983ksf

YTD leasing volume

Leasing activity YTD has experienced a significant slowdown, with a 29.8% decline from the same time period in 2022. This is evident when considering the average lease size this year has hit the lowest mark in two decades, further presenting the impact of economic uncertainty and the growing prevalence of remote work models.

Source: AVANT by Avison Young, CoStar

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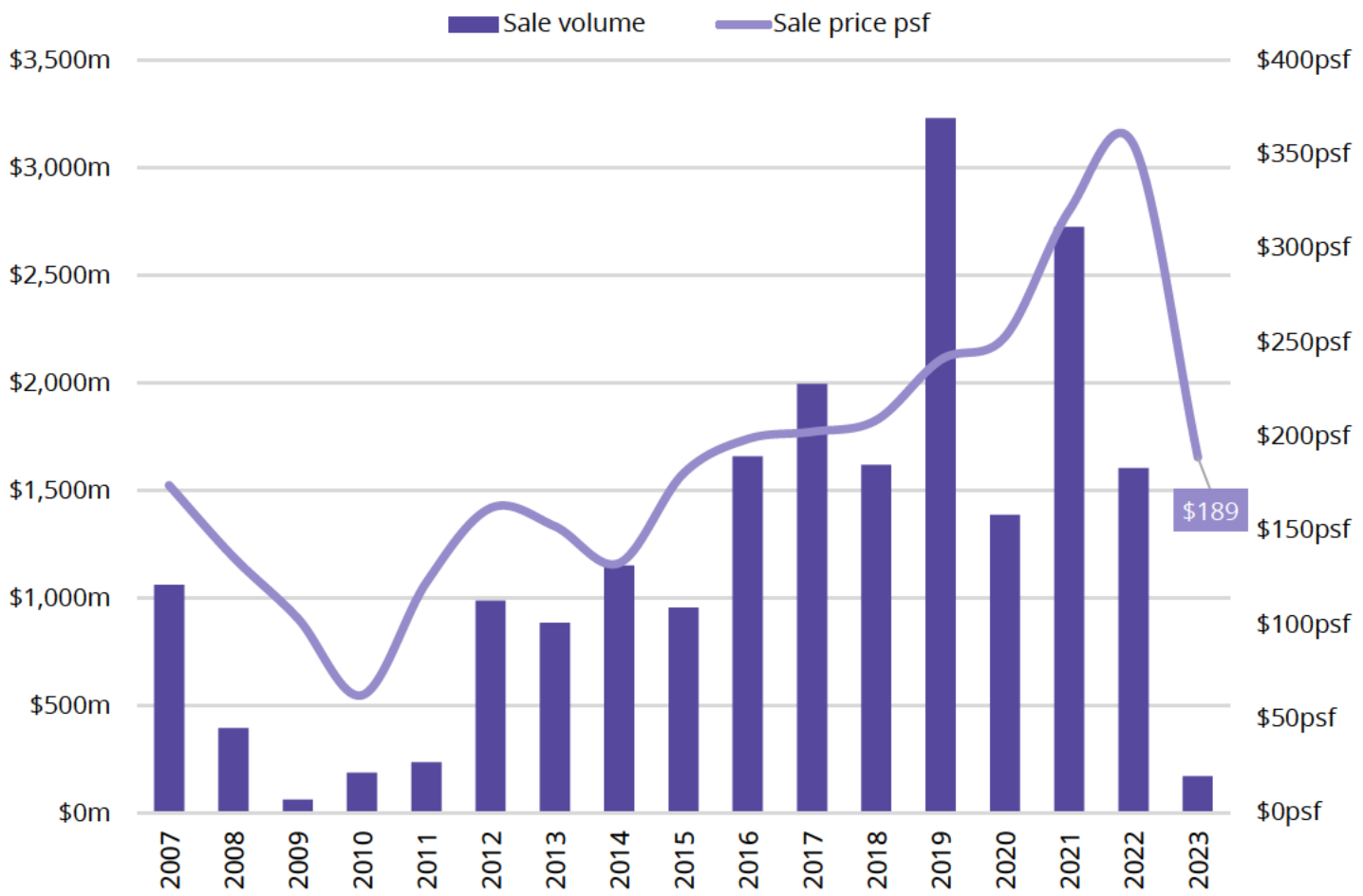
Yearly investment volume



The convergence of economic uncertainty and the adoption of remote work models has both reduced office investment volume and pricing.

Source: AVANT by Avison Young, CoStar

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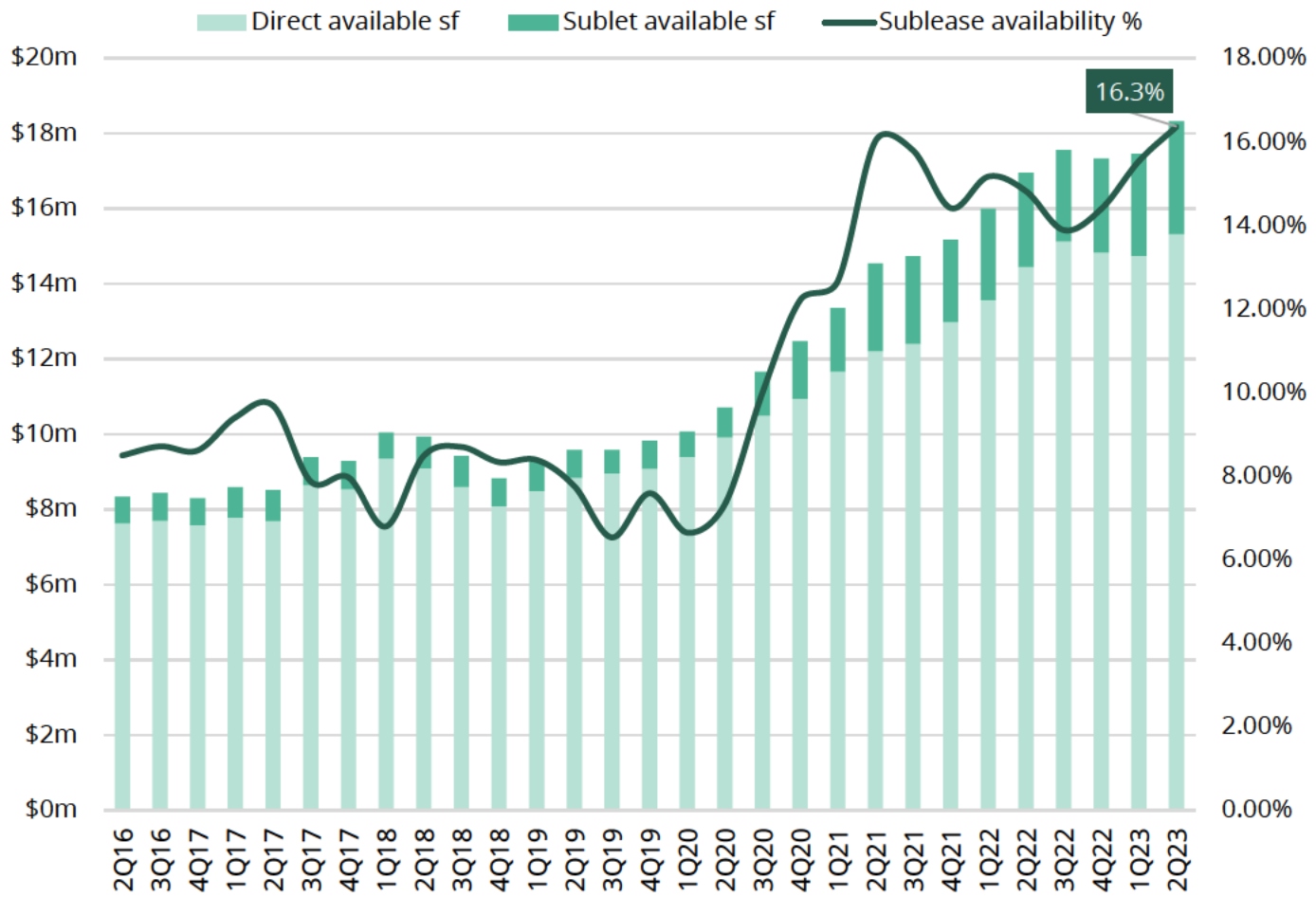
Total availability



Total office availability has reached a new high in Charlotte, while subleases are accounting for >16% of the total available space this quarter.

Source: AVANT by Avison Young, CoStar

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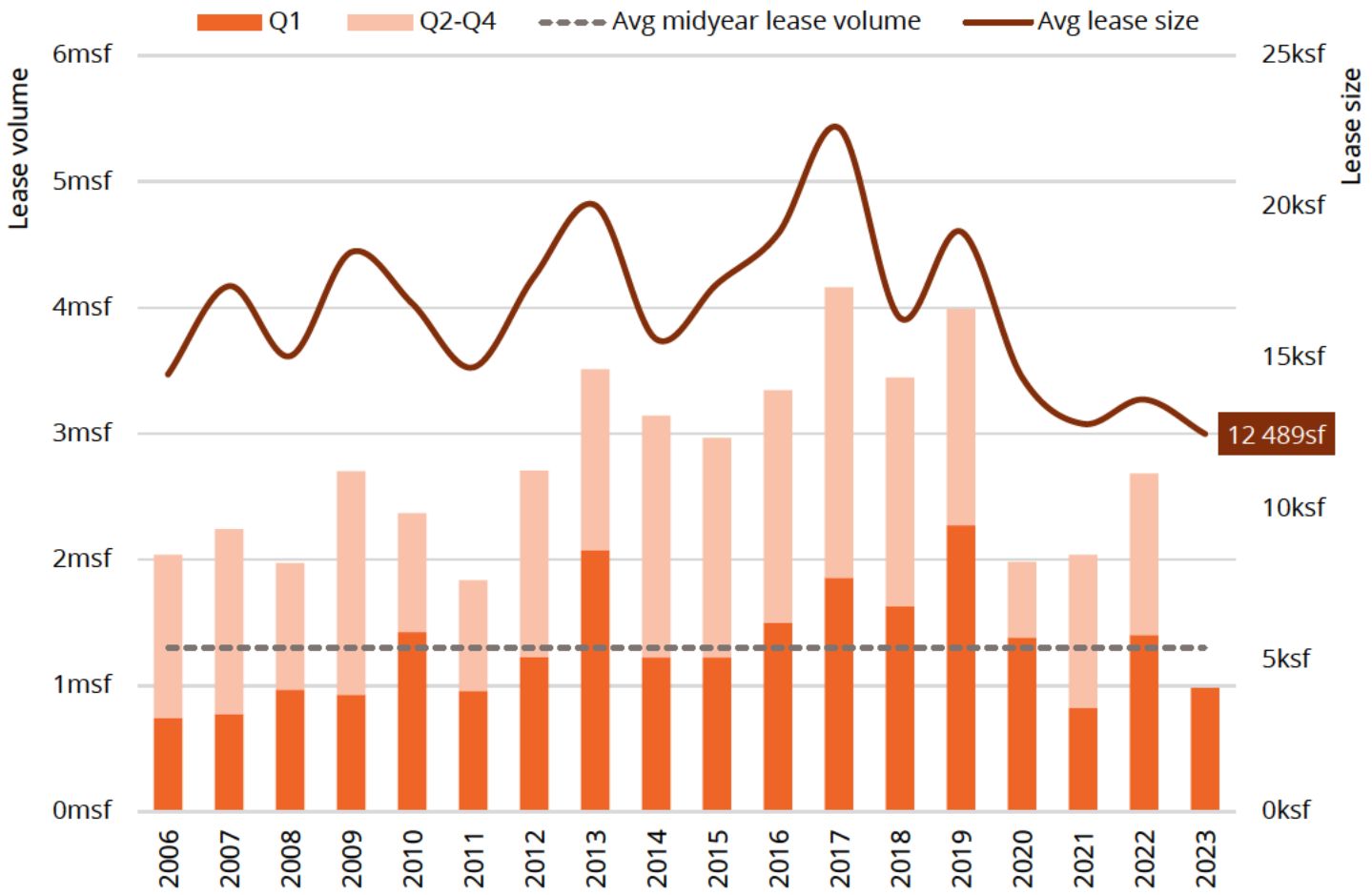
Midyear leasing activity



Midyear 2023 leasing activity has fallen YoY, while the average lease size hits a market low of 12,489sf.

Source: AVANT by Avison Young, CoStar

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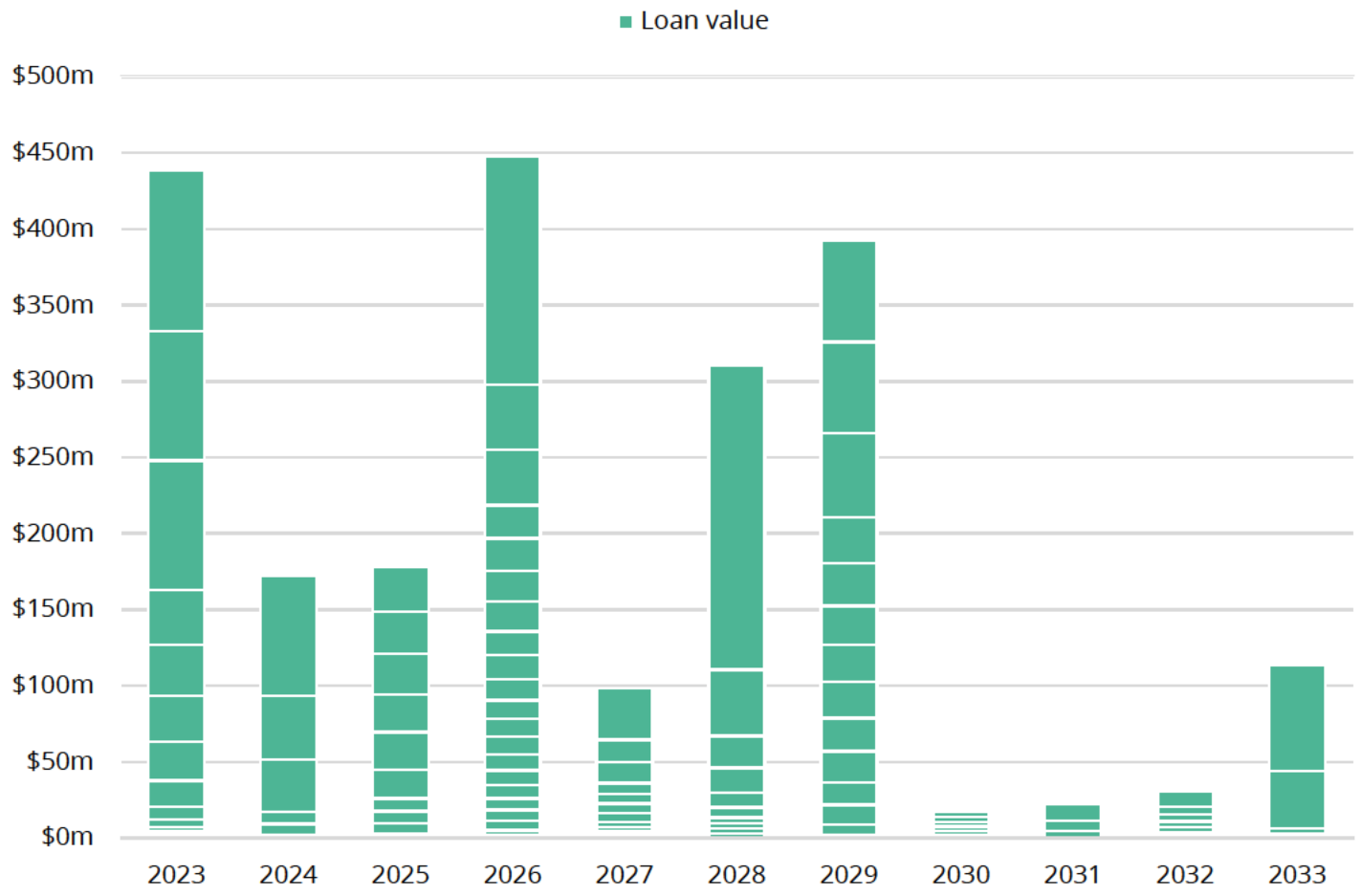
CMBS loan maturities



There are 106 CMBS office loans maturing in the next ten years throughout the Charlotte Metro, the majority of which have an avg interest rate of 4.6%.

Source: AVANT by Avison Young, CoStar

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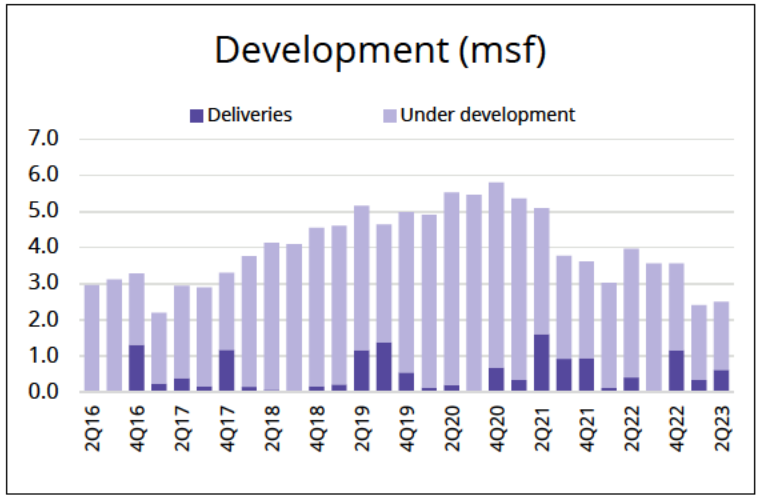
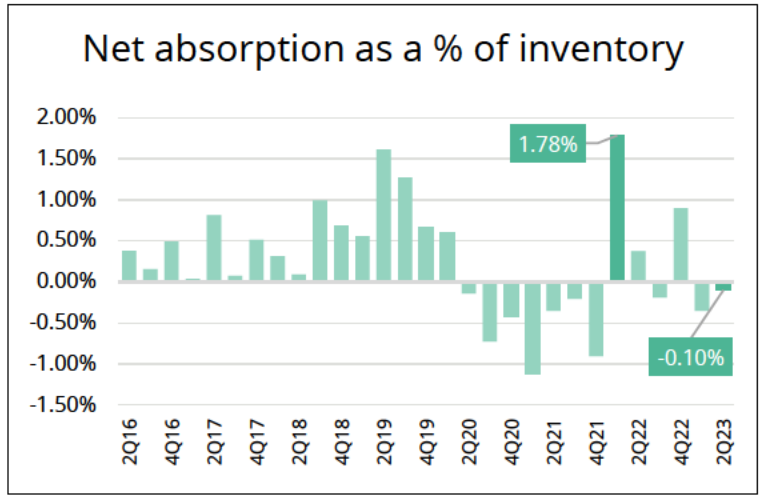
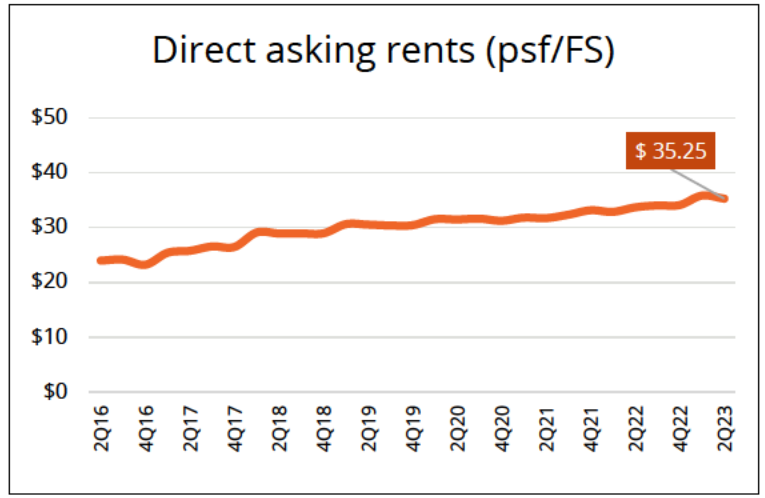
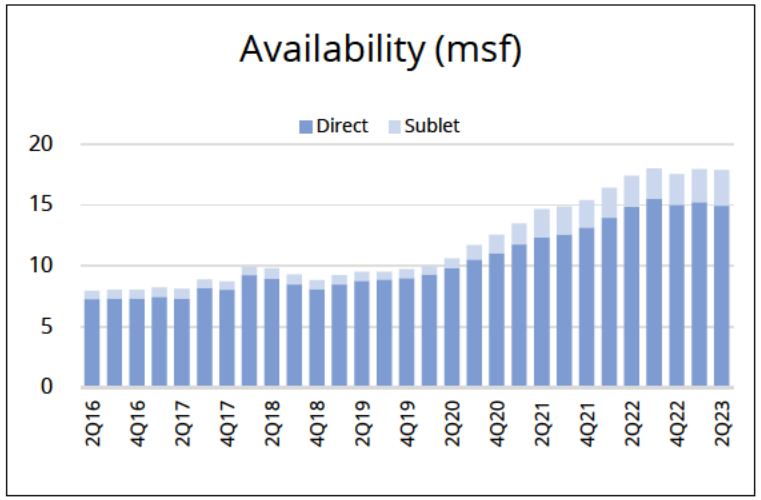
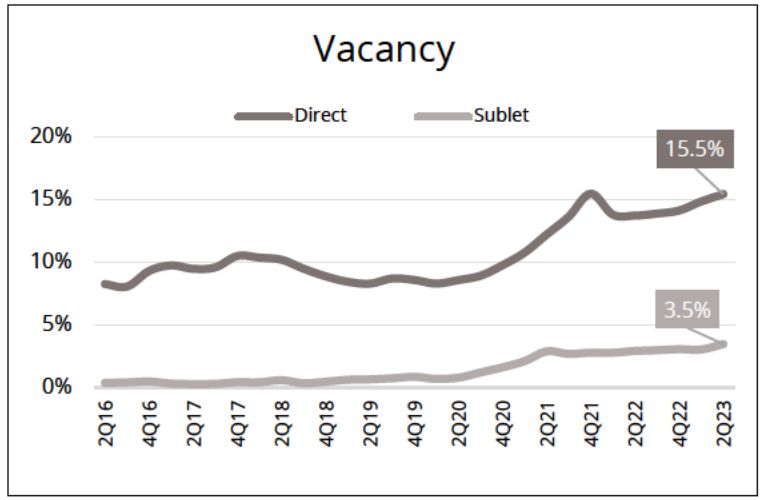
Charlotte office market indicators

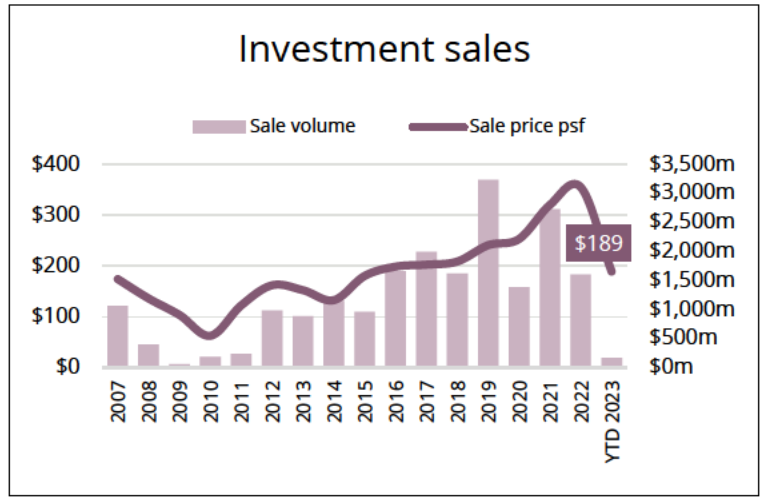












Source: AVANT by Avison Young, CoStar

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Charlotte office market activity

Recent leasing activity

Tenant Name	Property	Sign Date	Size (sf)	Transaction Type	Lease Type	Submarket
Ameriprise Financial	300 S Tryon St	May 2023	53,000	New	Direct	CBD
Snider Fleet Solutions	1081 Red Venture Dr	April 2023	50,388	New	Direct	South Carolina
Newell	8900 Northpointe Executive Park Dr	June 2023	49,916	New	Direct	North
Skyla Credit Union	3700 South Blvd	June 2023	46,989	New	Direct	Midtown/South End
Haynes & Boone	650 South Tryon St	April 2023	23,766	New	Direct	CBD

Recent sales activity

Buyer	Property	Sale Date	Sale Price	Sale Price (psf)	Submarket	Seller
Childress Klein	2101 Rexford Rd	June 2023	$31,000,000	$153	SouthPark	LRC Properties
Asana Partners	1435 W Morehead St	May 2023	$19,150,000	$364	Midtown/South End	Northridge Capital
Northpond Partners	2500 N Brevard St	June 2023	$12,500,000	$315	Plaza Midwood/Noda	FCP

Top projects under development

Address	Submarket	Delivery date	Building size (sf)	% Preleased	Developer
Legacy Union – Phase IV	CBD	Q3 2024	410,880	60%	Lincoln Harris
220 W White St – The Thread	South Carolina	Q4 2023	400,000	10%	The Keith Corporation
110 East Blvd – East West Station	Midtown/South End	Q1 2024	370,000	0%	Stiles Corporation

Source: AVANT by Avison Young, CoStar

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Charlotte office market stats

Submarket	Existing inventory (sf)	Deliveries sf (YTD)	Under development (sf)	Preleased (sf)	Direct vacancy	Sublet vacancy	Total vacancy	Q2 net absorption (sf)	Direct asking rent FS
CBD	24,542,816	-	410,880	102,720	16.3%	1.9%	18.2%	(211,122)	$40.75
Midtown/South End	7,190,215	337,708	565,324	140,200	8.9%	2.4%	11.3%	30,909	$46.36
Plaza Midwood/Noda	1,576,875	150,000	285,748	79,527	23.7%	0.1%	23.8%	151,359	$42.11
Urban Subtotal	**33,309,906**	**487,708**	**1,261,952**	**322,447**	**15.1%**	**1.9%**	**17.0%**	**(28,854)**	**$42.03**
Airport	11,133,685	190,000	-	9,395	15.4%	7.3%	22.7%	59,393	$26.74
East Charlotte	1,807,987	-	-	4,655	14.2%	0.0%	14.2%	15,018	$20.71
North Charlotte	1,417,326	262,000	225,000	24,975	16.7%	2.4%	22.6%	(8,913)	$33.59
Park Road	845,731	-	-	-	29.1%	3.9%	33.0%	127,334	$35.48
South Carolina	3,656,336	-	400,000	81,202	12.8%	14.8%	27.6%	(127,566)	$28.38
South Charlotte	1,795,691	-	-	-	7.8%	0.3%	8.1%	(10,404)	$27.82
South/485	6,327,308	-	-	-	25.0%	4.7%	29.8%	(65,374)	$36.68
Southeast Charlotte	1,194,797	-	-	-	11.7%	2.9%	14.5%	(1,116)	$23.26
SouthPark	4,720,223	-	-	45,357	14.1%	2.7%	16.8%	-	$37.67
University	7,145,611	-	-	-	15.7%	3.1%	18.9%	(35,893)	$26.90
Suburban Subtotal	**42,771,334**	**452,000**	**625,000**	**165,585**	**16.4%**	**5.1%**	**21.9%**	**(47,521)**	**$30.12**
Market total	**76,081,334**	**939,708**	**1,886,952**	**488,032**	**15.8%**	**3.7%**	**19.7%**	**(76,375)**	**$35.25**

Source: AVANT by Avison Young, CoStar

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Office insights glossary of terms

Demand

- **Leasing activity:** total square footage of relocations, renewals, expansions and subleases expressed when the leases are signed, not when tenants take physical occupancy of the space
- **Absorption:** period-over-period change in occupied square footage

Supply

- **Direct vacancy rate:** space operated by landlords that is ready for immediate occupancy
- **Sublease vacancy rate:** space operated by sublandlords that is ready for immediate occupancy
- **Total vacancy rate:** sum of direct vacancy rate and sublease vacancy rate
- **Availability rate:** space that is vacant plus space that will become vacant over an indefinite time horizon, including spaces that are occupied by vacating tenants and under-construction properties

Office rents and concessions

- **Asking rents:** pricing guidance provided by landlords to tenants for available space expressed as full service (FS)
- **Base rents:** fair market value of market-level lease pricing based on representative executed leases, expressed as full service (FS)
- **Free rent period:** months of free rent that are typically provided upfront by landlords to tenants as a concession to offset the total cost of a lease and/or the construction timeline of an office suite
- **Tenant improvement allowance:** an allowance expressed in dollars per square foot provided from landlords to tenants to offset build-out, engineering, space planning and related permit costs
- **Net effective rent:** base rents discounted by the dollar values of tenant improvement allowance and free rent concessions expressed as full service (FS)

Capital markets

- **Investment volume:** office sales dollars expressed when the transactions close and based on inventory thresholds; partial-interest sale dollar amounts are not grossed-up to reflect the 100% value of the sale
- **Asset pricing:** unweighted average per-square-foot asset pricing of market-level closed sales
- **Cap rate:** net operating income divided by sale price; this measurement of market-level investment returns is calculated as an unweighted average based on closed investment sales

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Council Rebuttal Exhibit 2

MARKETBEAT

CHARLOTTE

Office Q2 2023

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	YoY Chg	12-Mo. Forecast
18.0% Vacancy Rate	▲	▲
-253.3K Q2 Net Absorption, SF	▲	▲
$33.53 Asking Rent, PSF	▲	▲

(Direct, All Property Classes)

ECONOMIC INDICATORS Q2 2023

	YoY Chg	12-Mo. Forecast
1.35M Charlotte Employment	▲	▲
3.2% Charlotte Unemployment Rate	▬	▲
3.6% U.S. Unemployment Rate	▬	▲

Source: BLS

ECONOMIC OVERVIEW

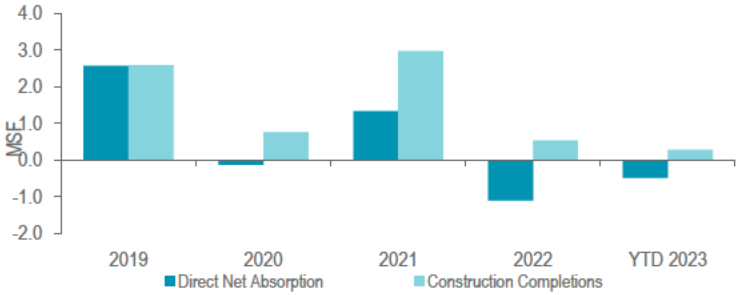
Amidst a backdrop of economic turbulence, the Charlotte region has demonstrated resilience. Notably, non-farm employment has experienced robust growth of 3.4% year-over-year (YOY), driven by key sectors. Charlotte maintained a strong economic climate for corporate businesses, boasting some large out of market announcements including Ameriprise Financial and Alpitronic Americas. Ameriprise singed a new lease in the Central Business District (CBD), set to bring 400 new jobs to the region. Alpitronic, an Italian based Electric Vehicle (EV) company, purchased a facility off Westpark Dr to establish its Americas HQ and bring 300 new jobs to join the growing Battery Belt EV market. Additionally, the region's unemployment rate stands at an impressive 3.2%, 40 basis points (bps) below the national average.

SUPPLY & ABSORPTION

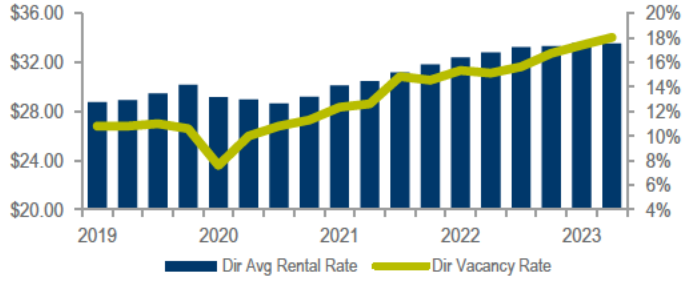
The direct vacancy rate in Metro Charlotte increased for the fourth consecutive quarter to 18.0%, a 60-bps increase quarter-over-quarter (QOQ) and 290-bps increase YOY. The overall rate rose to 22.0%, with sublease vacancy climbing 40 bps QOQ to 3.9%. National trends show vacancy rising across the board, with sectors such as Tech and Banking leading the way on hybrid/remote workforce. This resulted in Charlotte's strong banking-backed economy recording an overall vacancy rate that was 280 bps higher than the national average. The CBD/Uptown submarket had a substantial increase in direct vacancy, up 160-bps QOQ and 330-bps YOY to 16.5%. On the flip side, seven of the twelve suburban submarkets recorded a drop in direct vacancy QOQ, with Midtown/South End notably falling 70 bps to 15.6% as tenants began to occupy space in new deliveries. Although Class B assets had the higher overall vacancy rate at 25.0%, older Class A product remained a large contributor of readily available supply for perspective occupiers, specifically properties constructed prior to 2000, which accounted for 41.5% of the market's overall vacancy.

Direct absorption ended the quarter at -253,348 square feet (sf), driven by -297,244 sf of net occupancy losses in the CBD/Uptown submarket. A common trend that drove vacancy in Q2 was large single tenant users downsizing office space to minimize business expenses. Some of the top downsizes included Wells Fargo vacating more than 100,000 sf in One Wells Fargo Center, Campbell vacating its 104,000-sf space for sublease in Ballantyne 3, and Alston & Bird vacating its 88,000-sf space in One South at the Plaza for new space at Vantage South End. While these large single tenant users were downsizing primarily out of the CBD/Uptown submarket, move ins to Midtown/South End buildings like Vantage South End led to occupancy gains of 133,850 sf. Alston & Bird, Holland & Knight and Accenture represented more than 100,000 sf of gains as flight to quality continued to be the primary driver within the Greater Charlotte area. Absorption figures have been impacted negatively from conservative market conditions where deals are taking longer to finalize, a trend given looming recession risk.

SPACE DEMAND / DELIVERIES



DIRECT VACANCY & ASKING RENT



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CONSTRUCTION

Charlotte had one new delivery in Q2 with 2825 South completing for 133,735 sf of traditional office space in the Midtown/South End submarket. Pre-leasing velocity slowed with this building delivering only 21.8% leased to Samet and Aston Properties. This brought the yearly total to three new completions, making up 269,708 sf of deliveries year-to-date (YTD). Office groundbreakings slowed as precaution clouded the market, but nearly 2.2 million square feet (msf) remained under construction of which 1.5 msf is set to deliver this year.

RENTAL RATES

Rental rates in the Charlotte region dropped for the first time since Q3 2020, as overall rental rates decreased 0.8% QOQ to $33.28 per square foot (psf). This decrease was primarily due to a rise in vacancy in older Class A and Class B product, while space in Trophy and newer Class A buildings leased up, taking premium rents off the market. In the CBD, WeWork left its 141,201-sf space in the First Citizens Bank Plaza building, an older Class A asset listed at $35.00 psf. Meanwhile, Ameriprise Financial leased 53,020 sf of premier office space in 300 S Tryon which was asking $44.00 psf. This dual effect has driven rental rates down in the CBD/Uptown submarket 0.8% QOQ to $37.26 psf. The submarkets that recorded substantial rental rate decreases were CBD/Uptown, South Charlotte and South/485. Rates should continue to remain stagnant as the increased vacancy in Class A- and B assets with lower tier rents are counteracted as the 2.2 msf of Trophy product with an average asking rate of $47.63 psf delivers throughout the rest of the year.

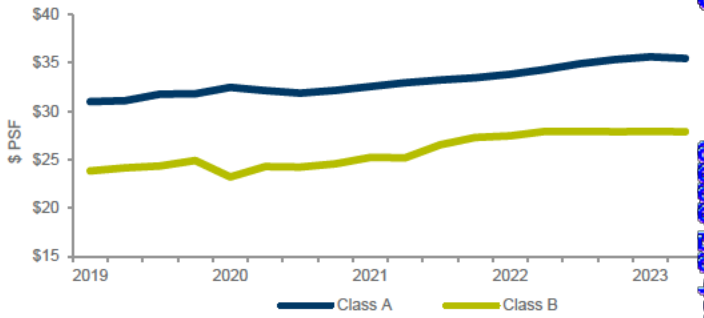
DEMAND

New leasing activity reported 460,570 sf of deals signed in Q2 marking a 2.4% increase in activity QOQ. Leasing continued to transact within smaller floorplans, as 71.5% of new deals were inked in spaces smaller than 20,000 sf, a trend expected to continue as tenants right size space. As small tenants drove Charlotte's current office market demand, there were still positive signs of large tenants scoping out the market. Two new leases above 40,000 sf were signed this quarter with financial service firm Ameriprise Financial and a local bank, Skyla Credit Union, taking Class A trophy space. New leasing volume continued to be highly concentrated in suburban markets, accounting for 83.1% of all new deals, with a primary focus in the Midtown/South End submarket which had nearly 100,000 sf of new leases signed in Q2. CBD/Uptown, South/485, and SouthPark all followed closely with 70,000 sf – 85,000 sf of new leasing. These four submarkets represented 73.6% of Charlotte's new leasing activity in Q2 due to the high concentration of newer, highly amenatized Class A space. As Charlotte is foundationally built off large tenants moving from Northern and Midwest metros, leasing is expected to remain low in the near term.

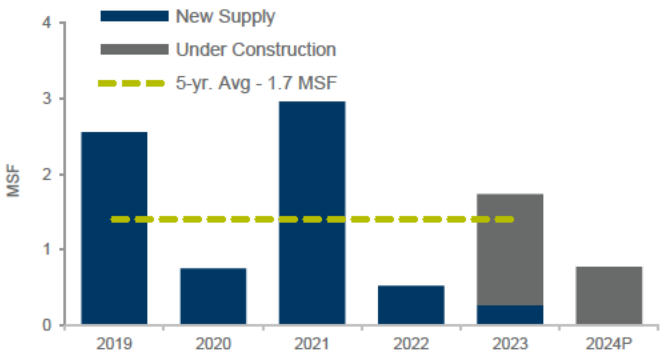
OUTLOOK

- As the trend of tenants downsizing continues, demand of large blocks of space will not be able to keep up with supply causing vacancy to rise in coming quarters.
- Spec Suites and other creative renovation/repurpose projects will continue to grow in popularity as landlords are looking to gain any competitive advantage with newer, high-quality space to help tenants attract and retain talent.
- As companies continue to draw employees back into the office with amenity-rich spaces, flight to quality to new Class A properties will continue to drive a divergence of Class A and B rental rates.
- With news of large corporations forcing employees back to office, the momentum driven office market may only need minimal positive news from big players to begin climbing back to normality.

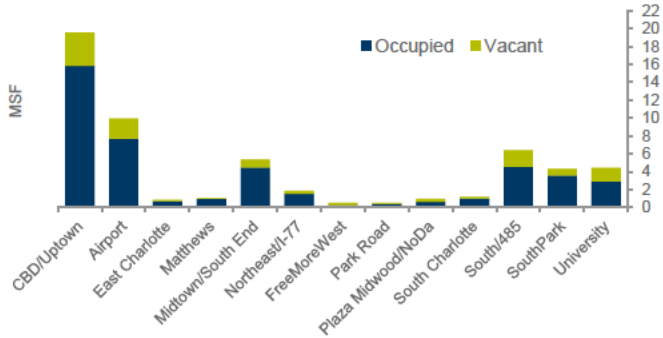
ASKING RENT COMPARISON



NEW SUPPLY



SUBMARKET COMPARISON



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MARKETBEAT

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Office Q2 2023

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MARKET STATISTICS

SUBMARKET	INVENTORY (SF)	DIRECT VACANT (SF)	DIRECT VACANCY RATE	SUBLET VACANT (SF)	OVERALL VACANCY RATE	CURRENT QTR OVERALL NET ABSORPTION	YTD OVERALL NET ABSORPTION (SF)	YTD LEASING ACTIVITY (SF)	UNDER CNSTR (SF)	YTD DELIVERIES (SF)	DIRECT AVG ASKING RENT	OVERALL AVG ASKING RENT
CBD/UPTOWN TOTALS	19,577,894	3,220,899	16.5%	516,807	19.1%	-292,450	-412,617	126,547	410,000	0	$37.26	$37.12
Airport	9,957,258	1,478,774	14.9%	814,977	23.0%	-64,004	-78,715	63,628	0	0	$26.23	$25.94
East Charlotte	836,024	149,062	17.8%	0	17.8%	-7,424	-4,792	1,704	0	0	$18.01	$18.01
Matthews	1,035,009	61,353	5.9%	31,475	9.0%	42,548	11,073	22,873	0	0	$21.78	$21.27
Midtown / South End	5,361,656	836,890	15.6%	67,687	16.9%	99,480	122,664	176,305	509,395	156,828	$44.19	$43.80
Northeast / I-77	1,865,859	234,555	12.6%	98,027	17.8%	8,936	-4,265	80,856	0	0	$29.45	$28.83
FreeMoreWest	507,500	232,042	45.7%	29,950	51.6%	-8,590	-8,590	19,720	200,000	0	$39.84	$39.89
Park Road	506,133	72,869	14.4%	33,006	20.9%	9,097	10,268	25,949	0	0	$34.73	$31.70
Plaza Midwood / NoDa	961,679	335,315	34.9%	1,824	35.1%	3,014	-10,582	36,093	341,157	0	$37.86	$37.95
South Charlotte	1,167,875	160,724	13.8%	6,364	14.3%	-7,332	-26,358	34,542	0	0	$27.89	$27.43
South / 485 / Ballantyne	6,392,582	1,537,183	24.0%	291,403	28.6%	-251,556	-344,414	116,860	0	0	$36.35	$36.12
SouthPark	4,321,501	630,541	14.6%	118,966	17.3%	38,528	-28,436	154,034	0	0	$36.15	$36.11
University	4,432,946	1,311,167	29.6%	228,974	34.7%	-88,228	-185,501	51,085	770,000	0	$26.42	$26.29
SUBURBAN TOTALS	37,346,022	7,040,475	18.9%	1,722,653	23.5%	-225,531	-547,648	783,649	1,820,552	156,828	$31.81	$31.45
Class A	40,929,976	7,254,069	17.7%	1,252,024	20.8%	-254,741	-391,301	730,681	2,230,552	156,828	$35.78	$35.45
Class B	15,993,940	3,007,305	18.8%	987,436	25.0%	-263,240	-568,964	179,515	0	0	$28.09	$27.88
CHARLOTTE TOTALS	56,923,916	10,261,374	18.0%	2,239,460	22.0%	-517,981	-960,265	910,196	2,230,552	156,828	$33.53	$33.28

**Rental rates reflect full service asking*

KEY LEASE TRANSACTIONS Q2 2023

PROPERTY	SUBMARKET	TENANT	RSF	TYPE
300 S Tryon	CBD/Uptown	Ameriprise Financial	53,020	New Lease
The Station at LoSo – Bldg 3	Midtown / South End	Skyla Credit Union	46,957	New Lease
Three Morrocroft Centre	SouthPark	TIAA, FSB	25,975	Sublease
Legacy Union – Phase II	CBD/Uptown	Haynes & Boone	23,766	New Lease
1616 Center	Midtown	Palmetto Solar	17,963	New Lease

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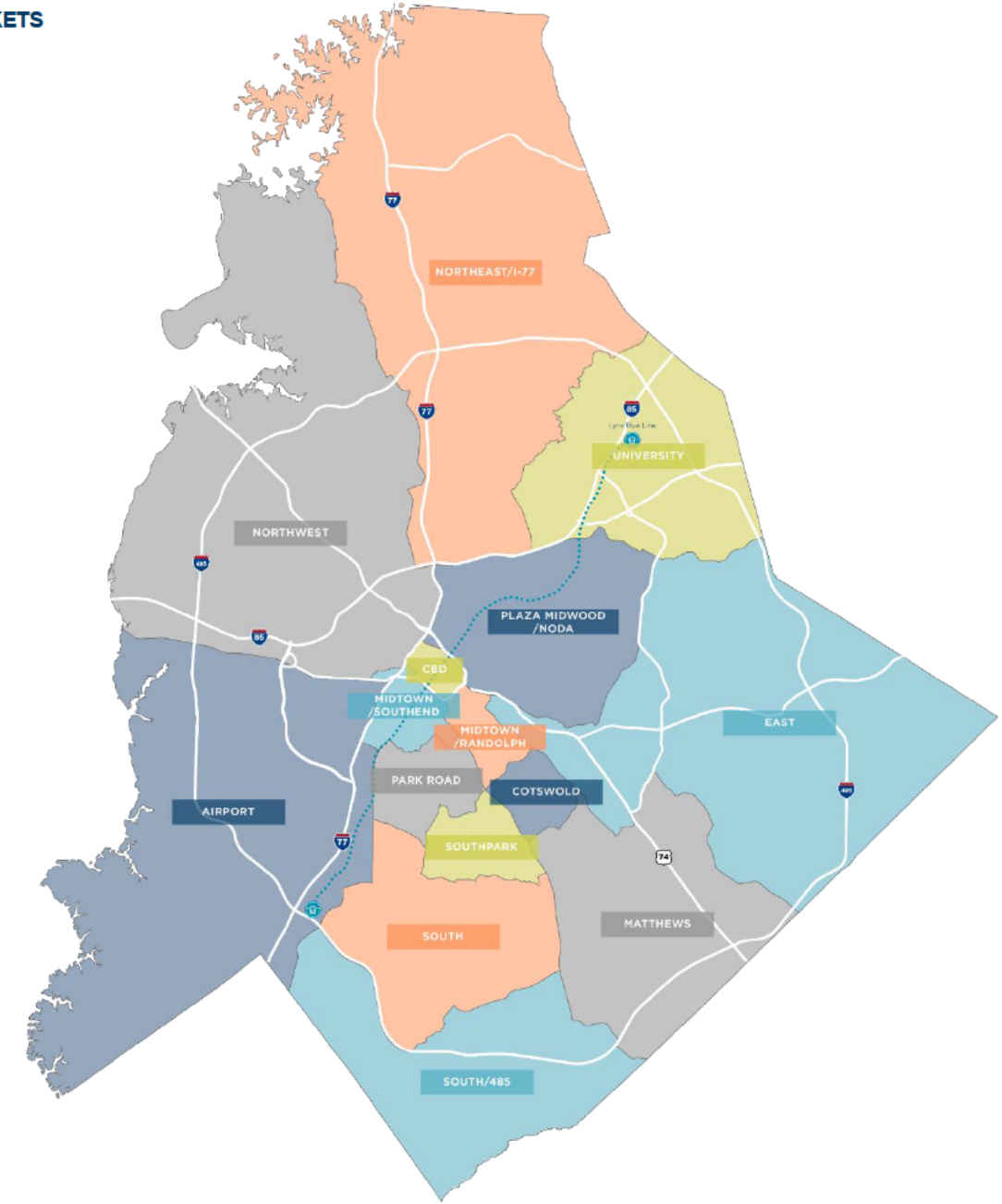
OFFICE SUBMARKETS



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Charlotte

Trophy assets continue to separate from the rest of the market in quality, cost and performance

- Trophy buildings continued to separate from Class A, commanding a 23% premium on direct asking rents.
- Owners of current Class A product have an opportunity to deploy capital and separate from the rest of the class with a development cycle closing.
- The upcoming deliveries of 110 East and Legacy Union IV will test the competition for tenants between South End and Uptown.

As H1 2023 closed, the growing bifurcation of the office market became the strongest it has been in recent history. The gap between "good" and "great" product, Class A and Trophy, respectively, continued to be exacerbated by the present environment of constrained capital and construction costs. Trophy buildings commanded a 23% premium above Class A on direct asking rents last quarter. Historic premiums have been as high as 40% and fell to 10% during the pandemic.

Proposed projects continued to delay groundbreakings last quarter. The longer these projects are delayed, the larger the lull period in deliveries after current under-construction projects deliver. This upcoming lull will provide an opportunity for struggling Class A properties to differentiate themselves and fill a vacuum following the lease-up of the final deliveries in the current construction wave. Investors willing to deploy capital in these properties can differentiate and test what market may exist for Class A+ product.

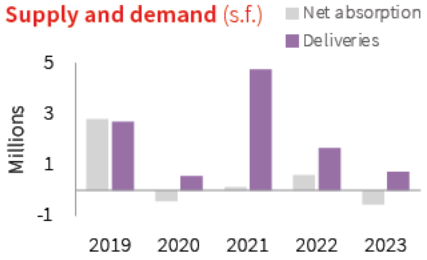
The leasing performance of two anticipated deliveries – 110 East and Legacy Union IV – will provide clarity on how the South End and Uptown submarkets compete. It is possible that South End's dominant performance on the leasing market has been because of location, construction or both. Once adjusting for new deliveries, South End post-2015-built properties performed at a 2:1 net absorption ratio compared to Uptown since 2022. While this ratio is decidedly in favor of South End, it is not as strong as market sentiment indicates, which suggests that a robust construction pipeline has been the primary driver of success.

Outlook

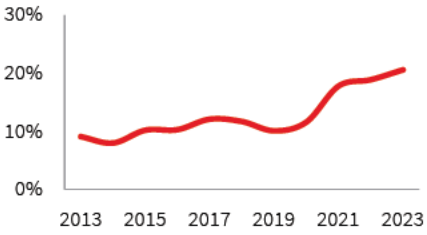
The market awaits capital activity to facilitate clarity for the market, whether through sales, renovations or other expenditures. In the meantime, bifurcation in perceived quality and rental rates will increase, especially with historic precedent.

Fundamentals	Forecast
YTD net absorption	-564,683 s.f. ▲
Under construction	2,226,960 s.f. ▼
Total vacancy	20.6% ▶
Sublease vacancy	1,913,194 s.f. ▶
Direct asking rent	$34.77 p.s.f. ▶
Sublease asking rent	$27.70 p.s.f. ▼
Concessions	Rising ▲

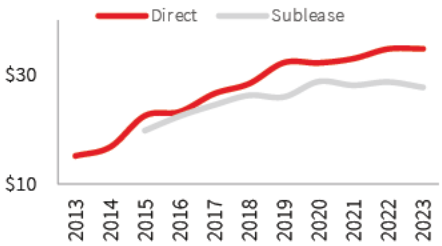
Supply and demand (s.f.)



Total vacancy (%)



Average asking rent ($ p.s.f.)



For more information, contact: Brett Cox | Brett.Cox@jll.com

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JLL Research Report

Office Statistics

	Class	Inventory (s.f.)	Total net absorption (s.f.)	YTD total net absorption (s.f.)	YTD total net absorption (% of stock)	Direct vacancy (%)	Total vacancy (%)	Average direct asking rent ($ p.s.f.)	YTD Completions (s.f.)	Under Development (s.f.)
FreeMoreWest	Totals	991,901	7,400	24,366	2.5%	31.1%	32.0%	$39.36	62,000	200,000
Midtown/South End	Totals	5,898,729	290,605	474,649	8.0%	12.9%	14.5%	$45.45	419,778	431,000
NoDa/Plaza Midwood	Totals	755,079	2,552	52,275	6.9%	36.1%	36.4%	$39.80	0	410,960
Uptown	Totals	22,930,461	121,293	-891,370	-3.9%	20.2%	21.8%	$37.10	0	415,000
CBD	**Totals**	**30,576,170**	**421,850**	**-340,080**	**-1.1%**	**19.5%**	**21.1%**	**$38.86**	**481,778**	**1,456,960**
Airport	Totals	10,549,584	-43,877	83,457	0.8%	13.7%	21.6%	$26.51	61,500	0
East Charlotte	Totals	1,091,385	65,938	116,628	10.7%	23.1%	23.1%	$23.64	176,696	0
Highway 51/Ballantyne	Totals	7,737,979	-158,932	-253,678	-3.3%	22.1%	25.2%	$35.73	0	0
Northeast/I-77	Totals	2,284,758	-11,483	-24,957	-1.1%	13.5%	16.1%	$29.86	0	0
Park Road	Totals	657,290	4,893	-2,240	-0.3%	33.9%	39.0%	$36.36	0	0
Southeast Charlotte	Totals	806,414	45,944	14,796	1.8%	10.3%	14.2%	$21.54	0	0
Southpark	Totals	4,876,497	-16,726	-18,435	-0.4%	13.5%	15.6%	$37.31	0	0
University	Totals	8,152,533	-86,188	-140,174	-1.7%	14.7%	16.5%	$26.74	0	770,000
Suburban	**Totals**	**36,156,440**	**-200,431**	**-224,603**	**-0.6%**	**16.3%**	**20.3%**	**$30.57**	**238,196**	**770,000**
Charlotte	**Totals**	**66,732,610**	**221,419**	**-564,683**	**-0.8%**	**17.8%**	**20.6%**	**$34.77**	**719,974**	**2,226,960**
FreeMoreWest	A	644,977	8,689	24,935	3.9%	40.8%	40.8%	$39.53	62,000	0
Midtown/South End	A	4,439,239	266,648	505,999	11.4%	15.6%	16.6%	$46.29	419,778	431,000
NoDa/Plaza Midwood	A	251,690	-1,824	34,675	13.8%	13.3%	14.0%	$41.16	0	270,000
Uptown	A	18,740,505	160,732	-278,289	-1.5%	18.5%	20.4%	$39.13	0	415,000
CBD	**A**	**24,076,411**	**434,245**	**287,320**	**1.2%**	**18.5%**	**20.2%**	**$40.78**	**481,778**	**1,116,000**
Airport	A	6,213,171	-57,563	9,865	0.2%	12.3%	15.7%	$27.81	0	0
East Charlotte	A	134,360	0	0	0.0%	0.0%	0.0%	$0.00	0	0
Highway 51/Ballantyne	A	6,284,531	-161,340	-255,999	-4.1%	25.2%	29.1%	$36.03	0	0
Northeast/I-77	A	1,338,799	26,206	15,094	1.1%	15.0%	18.4%	$30.63	0	0
Park Road	A	296,824	3,558	1,475	0.5%	20.1%	31.3%	$35.74	0	0
Southeast Charlotte	A	165,000	0	-31,475	-19.1%	11.1%	30.2%	$22.00	0	0
Southpark	A	3,440,916	11,862	-2,397	-0.1%	15.0%	17.3%	$38.99	0	0
University	A	2,245,048	5,193	23,336	1.0%	21.6%	25.1%	$27.54	0	770,000
Suburban	**A**	**20,118,649**	**-172,084**	**-240,101**	**-1.2%**	**18.0%**	**21.6%**	**$33.06**	**0**	**770,000**
Charlotte	**A**	**44,195,060**	**262,161**	**47,219**	**0.1%**	**18.3%**	**20.8%**	**$37.27**	**481,778**	**1,886,000**
FreeMoreWest	B	346,924	-1,289	-569	-0.2%	13.1%	15.7%	$39.24	0	200,000
Midtown/South End	B	1,459,490	23,957	-31,350	-2.1%	4.8%	7.9%	$38.69	0	0
NoDa/Plaza Midwood	B	503,389	4,376	17,600	3.5%	47.5%	47.5%	$38.54	0	140,960
Uptown	B	4,189,956	-39,439	-613,081	-14.6%	27.5%	28.1%	$32.35	0	0
CBD	**B**	**6,499,759**	**-12,395**	**-627,400**	**-9.7%**	**23.2%**	**24.4%**	**$34.48**	**0**	**340,960**
Airport	B	4,336,413	13,686	73,592	1.7%	15.7%	30.1%	$25.26	61,500	0
East Charlotte	B	957,025	65,938	116,628	12.2%	26.4%	26.4%	$23.64	176,696	0
Highway 51/Ballantyne	B	1,453,448	2,408	2,321	0.2%	8.6%	8.6%	$32.23	0	0
Northeast/I-77	B	945,959	-37,689	-40,051	-4.2%	11.4%	12.8%	$28.35	0	0
Park Road	B	360,466	1,335	-3,715	-1.0%	45.3%	45.3%	$36.74	0	0
Southeast Charlotte	B	641,414	45,944	46,271	7.2%	10.1%	10.1%	$21.39	0	0
Southpark	B	1,435,581	-28,588	-16,038	-1.1%	10.0%	11.5%	$32.04	0	0
University	B	5,907,485	-91,381	-163,510	-2.8%	12.1%	13.2%	$26.26	0	0
Suburban	**B**	**16,037,791**	**-28,347**	**15,498**	**0.1%**	**14.1%**	**18.6%**	**$26.93**	**238,196**	**0**
Charlotte	**B**	**22,537,550**	**-40,742**	**-611,902**	**-2.7%**	**16.7%**	**20.3%**	**$30.21**	**238,196**	**340,960**
East Charlotte	C	0	0	0	0.0%	0.0%	0.0%	$0.00	0	0
Suburban	**C**	**0**	**0**	**0**	**0.0%**	**0.0%**	**0.0%**	**$0.00**	**0**	**0**
Charlotte	**C**	**0**	**0**	**0**	**0.0%**	**0.0%**	**0.0%**	**$0.00**	**0**	**0**

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Oct 05 2023

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 217

Docket No. E-7, Sub 1276

Date of Request: **June 30, 2023**
Date of Response: **July 11, 2023**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 217-2, was provided to me by the following individual(s): Quynh Pham Bowman, Developmental Assignment, and was provided to NC Public Staff under my supervision.

Jack Jirak
Deputy General Counsel
Duke Energy Carolinas

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Oct 05 2023

North Carolina Public Staff
Data Request No. 217
DEC Docket No. E-7, Sub 1276
Item No. 217-2
Page 1 of 1

Request:

2. Please provide the supporting documentation for the market rate based on Building Class for each year as follows:

	2023	2024	2025	2026
Market Rate based on Building Class	26.46	38.64	38.64	38.64

Response:

Please see DR 217-2 Attachment.pdf for the market rate support. The market rate is provided by a third party commercial real estate broker (Cushman & Wakefield). Upon review, the Facility Study for 2023 should have reflected a market rate of $36.04 not $26.46 from the 2021 data on page 2 of the attachment. The Facility Study for years 2024 - 2026 use the correct market rate of $38.64 from the 2023 data on page 1 of the attachment. The most current market rate was used for 2024 and beyond.

Council Rebuttal Exhibit 3

MARKETBEAT

CHARLOTTE

Office Q3 2022

CUSHMAN & WAKEFIELD

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MARKET STATISTICS

SUBMARKET	INVENTORY (SF)	DIRECT VACANT (SF)	DIRECT VACANCY RATE	SUBLET VACANT (SF)	OVERALL VACANCY RATE	CURRENT QTR DIRECT NET ABSORPTION	YTD DIRECT NET ABSORPTION (SF)	YTD LEASING ACTIVITY (SF)	UNDER CNSTR (SF)	YTD DELIVERIES (SF)	AVG DIRECT ASKING RENT (ALL CLASSES)*	DIRECT AVG ASKING RENT (CLASS A)*
CBD/UPTOWN TOTALS	19,391,482	2,469,428	12.7%	408,911	14.8%	19,976	-300,281	402,296	1,504,000	0	$37.46	$38.64
Airport	10,151,491	1,355,657	13.4%	683,663	20.1%	60,064	258,854	635,956	0	0	$25.52	$26.81
East Charlotte	855,651	155,290	18.1%	0	18.2%	-15,311	-12,602	10,287	0	0	$17.84	-
Matthews	1,031,707	107,913	10.5%	0	10.5%	-4,373	7,360	64,748	0	0	$19.52	$17.46
Midtown/Southend	5,025,780	862,391	17.2%	36,034	17.9%	70,924	187,613	363,324	793,995	369,883	$44.89	$46.61
Northeast / I-77	1,871,932	201,478	10.8%	111,659	16.7%	10,505	-9,612	62,059	0	0	$28.65	$29.14
FreeMoreWest	507,500	270,523	53.3%	9,950	55.3%	43,995	54,274	24,825	200,000	0	$36.81	$35.01
Park Road	506,133	64,691	12.8%	22,262	17.2%	-6,684	6,027	43,233	0	0	$34.13	$34.68
Plaza Midwood / NoDa	896,063	329,987	36.8%	0	36.8%	0	96,702	22,436	221,157	118,117	$34.32	$37.55
South Charlotte	1,169,636	114,448	9.8%	20,590	11.6%	-13,280	-28,655	28,787	0	0	$26.96	$27.32
South / 485 / Ballantyne	6,379,244	1,128,105	17.7%	148,158	20.0%	-13,551	-119,466	199,646	0	0	$36.13	$36.23
SouthPark	4,378,096	678,419	15.5%	53,330	16.7%	-1,193	-99,786	155,842	0	0	$36.50	$37.81
University	4,850,384	1,141,753	23.5%	169,345	27.0%	-5,685	10,163	92,093	770,000	0	$26.75	$27.32
SUBURBAN TOTALS	37,623,617	6,410,655	17.0%	1,254,991	20.4%	125,411	350,872	1,703,236	1,985,152		$31.80	$33.57
Class A	40,863,208	6,414,458	15.7%	959,788	18.1%	81,519	-58,070	1,555,602	3,203,152	0	$35.24	$35.24
Class B	16,151,891	2,465,625	15.3%	704,114	19.6%	63,868	108.661	549,930	286,000	488,000	$28.52	-
CHARLOTTE TOTALS	57,015,099	8,880,083	15.6%	1,663,902	18.5%	145,387	50,591	2,105,532	3,489,152	488,000	$33.24	$35.24

Rental rates reflect full service asking

KEY LEASE TRANSACTIONS Q3 2022

PROPERTY	SUBMARKET	TENANT	RSF	TYPE
8600 McAlpine Park Dr	Matthews	Charlotte FC	51,650	New Lease
One Independence Center	CBD/Uptown	Bank of London	38,654	New Lease
Vantage South End – East Tower	Midtown/South End	FlexCare	27,509	New Lease
Ally Center	CBD/Uptown	Driven Brands	26,753	Renewal
Legacy Union – Phase II	CBD/Uptown	Figure Technologies	23,854	Sublease

MARKETBEAT

CHARLOTTE

Office Q3 2021

CUSHMAN & WAKEFIELD

MARKET STATISTICS

SUBMARKET	INVENTORY (SF)	DIRECT VACANT (SF)	DIRECT VACANCY RATE	SUBLET VACANT (SF)	OVERALL VACANCY RATE	CURRENT QTR DIRECT NET ABSORPTION	YTD DIRECT NET ABSORPTION (SF)	YTD LEASING ACTIVITY (SF)	UNDER CNSTR (SF)	YTD DELIVERIES (SF)	AVG DIRECT ASKING RENT (ALL CLASSES)*	DIRECT AVG ASKING RENT (CLASS A)*
CBD / UPTOWN TOTALS	20,687,621	2,217,510	10.7%	502,872	13.1%	2,274	422,954	302,072	1,000,000	1,185,415	$34.71	$36.04
Airport	10,117,991	1,716,823	17.0%	720,439	24.1%	-112,710	-221,584	503,951	200,000	0	$24.27	$26.48
East	855,651	161,168	18.8%	0	18.8%	-536	30,155	22,138	0	0	$16.06	N/A
Matthews	1,031,707	158,140	15.3%	0	15.3%	-22,903	-24,003	21,293	0	0	$18.12	$18.46
Midtown	4,026,434	568,240	14.1%	31,146	14.9%	37,602	290,981	447,998	1,264,183	465,597	$39.04	$40.09
Northeast / I-77	1,861,379	138,924	7.5%	91,666	12.4%	33,949	106,542	149,939	0	0	$26.86	$27.80
FreeMoreWest	541,680	384,964	71.1%	29,950	76.6%	23,649	65,488	0	289,000	0	$33.00	$33.00
Park Road	506,133	84,403	16.7%	8,208	18.3%	565	-7,141	32,237	0	0	$32.84	$32.00
Plaza Midwood / NoDa	809,104	328,378	40.6%	0	40.6%	8,953	66,082	20,989	109,972	53,020	$30.99	$33.34
South	1,168,364	117,855	10.1%	0	10.1%	-3,237	-20,393	64,444	0	0	$26.65	$26.97
South / 485	6,376,662	1,281,511	20.1%	147,061	22.4%	-94,565	-178,971	270,966	0	463,966	$35.29	$35.66
SouthPark	4,366,937	597,661	13.7%	66,841	15.2%	-8,428	-55,124	160,985	0	0	$34.60	$36.49
University	4,856,444	1,196,319	24.6%	155,350	27.8%	-63,896	-60,841	82,694	770,000	159,487	$26.16	$27.29
SUBURBAN TOTALS	36,518,486	6,734,386	18.4%	1,250,661	21.9%	-201,557	-8,809	1,777,634	2,633,155	1,142,070	$29.16	$31.88
Class A	40,696,247	5,947,880	14.6%	882,471	16.8%	-120,076	431,629	1,496,826	3,344,155	2,274,465	$33.25	$33.25
Class B	16,509,860	3,004,016	18.2%	871,062	23.5%	-79,207	-17,484	582,880	289,000	53,020	$25.83	N/A
CHARLOTTE TOTALS	57,206,107	8,951,896	15.6%	1,753,533	18.7%	-199,283	414,145	2,079,706	3,633,155	2,327,485	$30.67	$33.25

Rental rates reflect full service asking

KEY LEASE TRANSACTIONS Q3 2021

PROPERTY	SUBMARKET	TENANT	RSF	TYPE
Overlook – 13146 Ballantyne Corporate Pl	South/485	Credit Karma	94,588	New Deal
Ten Water Ridge – 2725 Water Ridge Pky	Airport	Dentsply Sirona	61,549	New Deal
Overlook – 13146 Ballantyne Corporate Pl	South/485	Sompo International	43,123	New Deal

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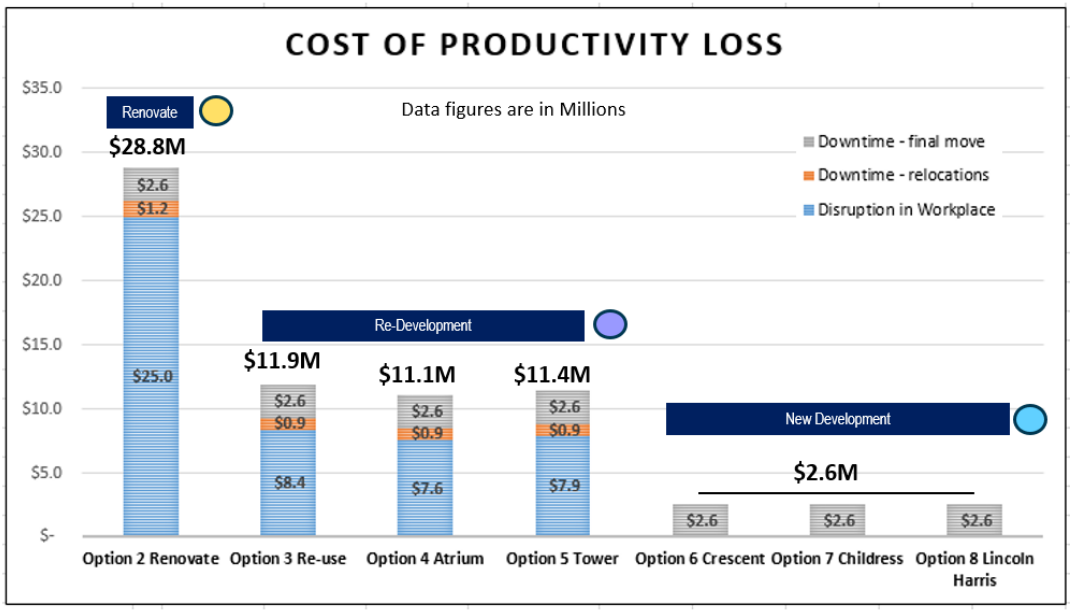
Cost of Productivity Loss (6-23-2016)

13

Intangible Costs

- Renovation and Re-Development will result in work disruption during the project at 526 Church St.
- Each re-location and move will result in 12 hours of downtime for each impacted FTE.
- All options have a $2.6M impact of the downtime per FTE to move into the final space.



SLIDE 13: Intangible Costs
Parameters

- Pay rate $40.00 per hour based on an average $80,000 salary

Disruption in work environment
Disruption is due to navigating through a construction site to get to/from work, waiting for elevators (construction workers are using same elevators), being distracted by additional noise in the workplace, etc.
Calculate productivity loss (8 hours per affected FTE * project duration months * $ pay rate)

- Renovation
  - 8 hours per month * 75% of 526 Church St. Occupants * entire project duration * $40 per hour
- Re-development
  - 8 hours per month * 50% of 526 Church St. Occupants * 33% of project duration * $40 per hour

Temporary Re-locations and Moves: Employees will have downtime during re-locations and moves to purge files, pack up belongings clean up old workspace, walk to new location, unpack belongings, organize their workspace, orient to the new work environment (where to find coffee, restrooms, printer, copier, etc.), and make connections.

Calculate productivity loss (12 hours per affected FTE * $ pay rate)

- 526 Church Street Current Occupants = 1,925
- Temporary Re-locations FTEs Affected = 1,925
- FTEs expected to be re-located twice for renovation = 25% of 1,925 = 481
- Re-locations: Total FTEs affected for renovation = 2,406
- Re-locations: Total FTEs affected for re-development = 1,925
- Downtime per FTE for each move or re-location = 12 hours
- Final Move FTEs Affected = 5,435

Why is New Development (Childress Klein) worth more than Renovation?

Childress Klein provides a higher quality, sustainable solution for the long-term and provides the highest return on the project funds expended [source: CBRE]

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		Why is New Development worth more than Renovation?		Is there a benefit for New Development?				
Category	Feature	Renovation	New Development (e.g. Childress Klein)	Increases Workforce Effectiveness	Promotes Energy Efficiency	Improves Community Perception	Results in Prudent Financials	Description of Benefit for New Development
Workforce Effectiveness								
	Natural Light	Minimal	Direct Access	Yes	Yes			- Higher productivity and less sick days - Use less energy (overhead lighting dims on sunny
	Air quality / temperature	Not Optimal	Optimal	Yes				Higher productivity with better air quality
	Elevators	Basic standard	Highly-efficient Destination elevators	Yes	Yes			- Contributes to productivity since less downtime - Saves energy and less wear and tear on equipment
	Worker well-being (WELL Building standards)	Partially achieved	Achieved	Yes				Healthier workforce due to air & water quality, lighting, comfort, fitness options, nourishment, etc.
	One Move	Highly disruptive	Less disruptive	Yes				Lower cost of Lost productivity (e.g. workforce downtime and distractions) during the construction
	Talent Acquisition / Retention	Less likely to attract/retain best talent	More likely to attract/retain best talent	Yes			Yes	Lower cost of recruiting since able to secure, retain talent.
Energy Leader								
	Sustainability	LEED Silver	LEED Gold	Yes	Yes			- Realized energy and water usage savings - Increased productivity in better quality environment
	Windows	Glazing is now high efficiency. The difference is limited perimeter glass.	Efficient, energy saving windows	Yes	Yes			Utility energy cost savings
	Green Roof Capabilities	none	Capacity for plant/vegetation growth		Yes	Yes		- Energy efficient insulating building from extreme weather and producing oxygen for cleaner air
Community								
	Lobby / Street Presence	No perceived changes, not welcoming	Welcoming, world-class			Yes		improves community perception
	Auditorium	sized for 250 people	sized for 450 people			Yes		Accommodates more people (shareholder meetings) which promotes better image/broader understanding
	Brand	Not very visible	Highly visible on Tryon Street			Yes	Yes	improves public perception
	Retail Amenities	Very Limited	Fully-integrated and vibrant	Yes		Yes	Yes	- More convenient retail saves workforce time - Increase in receivable leases.
Flexibility								
	Tenant capabilities	Limited to one tenant	Multi-tenant capabilities				Yes	Ability to lease space, if needed
	Space Layout	Large columns hinder flexibility and not conducive to marketplace demand	Supports workplace standards and greater flexibility for future change	Yes			Yes	Efficient workspaces and more flexibility to change as workplace standards evolve.
Value								
	Location	Church Street is not as marketable an address in current market	Market savvy location on Tryon				Yes	- Higher property sale value - promotes more retail opportunities
	Parking	Underground parking at Church Street is inefficient and limited	Underground parking optimizes use of prime real estate				Yes	- Optimizes utilization of commercial land - About 500 more available parking spaces
	Exit Terminal Value	Below market book value. Buildings are functionally obsolete	Premier, most prominent commercial property in uptown				Yes	- Highest terminal value - Will retain value the longest

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Evaluation of Decision Factors

The team developed an Evaluation tool based on the key decision factors which have an assigned weighting. For example, Cost represents 40% and Flexibility for future expansion is designated as 5%.

Each individual team member performed an independent, initial evaluation. Then, the team met to discuss and collaborate together to reach a consensus among the various options. The Top 3 selections are indicated below:

		Crescent Proposal		Lincoln Harris Proposal		Childress Klein Proposal		Redevelopment Reuse Exisiting		Redevelopment Infill w/Atrium		Redevelopment Tower		526 Renovation	
Categories	Weights	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score
Building Vision, Key Drivers															
ENERGY	15%	6	0.9	6	0.9	10	1.5	5	0.75	5	0.75	9	1.35	1	0.15
WORKPLACE	20%	8	1.6	6	1.2	10	2	5	1	6	1.2	9	1.8	1	0.2
COMMUNITY	10%	9	0.9	4	0.4	10	1	4	0.4	6	0.6	9	0.9	1	0.1
FLEXIBILITY	5%	10	0.5	3	0.15	9	0.45	1	0.05	1	0.05	8	0.4	1	0.05
COST	40%	5	2	6	2.4	5	2	3	1.2	1	0.4	3	1.2	10	4
DEVELOPER TEAM	10%	10	1	1	0.1	10	1	10	1	10	1	10	1	10	1
SCORE without Risk	100%		6.9		5.15		7.95		4.4		4		6.65		5.5

 # 2 **# 1** **# 3**

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From: Luhr, Nadia <Nadia.Luhr@psncuc.nc.gov>
Sent: Thursday, June 22, 2023 11:11 AM
To: Donaldson, Bob <Bob.Donaldson@duke-energy.com>
Cc: Metz, Dustin -psncuc.nc <Dustin.Metz@psncuc.nc.gov>; Nader, Jordan A <jordan.nader@psncuc.nc.gov>
Subject: RE: [EXTERNAL] Duke Energy Plaza Alternative Dates

Hi Bob,

I hope you're well!

I apologize for all the back and forth on the timing of the Duke Plaza site visit. Our workload has shifted a bit to allow us to perform this audit sooner than expected, so if possible, we would greatly appreciate moving this site visit forward to July 12-14, with the preference being July 13. This would also allow us to schedule the site visit to Cedar Cliff on an adjoining day, if that could be facilitated by Duke (e.g, if the Duke Plaza site visit were scheduled for July 13, the Cedar Cliff site visit could be scheduled for July 12 or July 14).

Again, apologies for shifting the timeframe again. There are many moving pieces with our investigation, and we appreciate your facilitation!

Nadia

--
Nadia L. Luhr
Staff Attorney
Public Staff - N.C. Utilities Commission
430 N. Salisbury Street, Suite 5060

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Raleigh, NC 27699-4300
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From: Donaldson, Bob <Bob.Donaldson@duke-energy.com>
Sent: Tuesday, June 20, 2023 4:51 PM
To: Nader, Jordan A <jordan.nader@psncuc.nc.gov>
Cc: Luhr, Nadia <Nadia.Luhr@psncuc.nc.gov>; Metz, Dustin <dustin.metz@psncuc.nc.gov>
Subject: RE: [EXTERNAL] Duke Energy Plaza Alternative Dates

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Good Afternoon,

Duke would like target Tuesday, July 25 (Preferred) or Wednesday, July 26 for the plaza tour dates.

Let me know if either of those work for the Public Staff.

Thanks,

Bob Donaldson, PE, CEM
Regulatory Affairs Manager - North Carolina

Duke Energy
410 S. Wilmington St., Raleigh, NC 27601
Mail Code NC20
office: 919.546.5451 cell: 919.812.3249
bob.donaldson@duke-energy.com

From: Nader, Jordan A <jordan.nader@psncuc.nc.gov>
Sent: Wednesday, June 14, 2023 5:24 PM
To: Donaldson, Bob <Bob.Donaldson@duke-energy.com>
Cc: Luhr, Nadia <Nadia.Luhr@psncuc.nc.gov>
Subject: [EXTERNAL] Duke Energy Plaza Alternative Dates

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Hi Bob,

Wanted to follow up after discussing with some of the other team members. Would we be able to do the last week of July (24th to 28th) audit of the Duke Energy Plaza?

Thanks,
Jordan Nader
Public Utilities Engineer
Energy Division
North Carolina Utilities Commission Public Staff
919.733.0898

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DE Plaza Schedule for
In-Service and Move Ins by floor

The information in this spreadsheet is subject to change

Floor Level	In Service Dates: Current Forecasted Finish (data date: 7.24.2023)	In Service Dates: Actual Finish (data date: 7.24.2023)	Move Ins (data date: 6.19.2023)	Business Function
Level 01 Back of House		5/22/2023	1/20/2023	Enterprise Protective Services (Security Office), Parking Office, Medical Suite, IT Storage Area
Level 01 Lobby (proper)		12/19/2022	1/27/2023	Reception Desk, Waiting Area, and Restrooms
Level 01 Experience Hall	10/3/2023		10/4/2023	amenity space - open to public
Level 01 Fitness/Wellness	10/9/2023		10/13/2023	amenity space - Duke Energy only
Level 07 Conference Cntr	9/19/2023		9/29/2023	Conference Center, Storm, Incident Support Team (IST), Auxiliary Call Center
Level 08		4/19/2023	4/21/2023	Trade Floor, Joint Information Center, Social Media, FERC Suite
Level 09		3/14/2023	3/17/2023	Legal, Corporate Audit Services and Ethics & Compliance
Level 10		7/20/2023	7/24/2023	Executive Level
Level 11	11/21/2023		11/24/2023	Executive Conference Floor
Level 12		12/19/2022	1/27/2023	External Affairs & Corp Comms, Carolinas Jurisdictions, FL&MW, Pricing & Strategy, Customer Exp, Solns & Svcs
Level 14		2/8/2023	3/17/2023	Human Resources
Level 15		2/10/2023	3/3/2023	Finance
Level 16		2/7/2023	3/3/2023	Finance
Level 17		2/7/2023	3/3/2023	Finance
Level 18		2/7/2023	8/25/2023	Natural Gas, External Affairs & Corp Comms
Level 19		2/7/2023	8/25/2023	Natural Gas
Level 20		2/7/2023	4/21/2023	Generation & Transmission Strategy, Enterprise Tech & Security
Level 21		2/7/2023	4/21/2023	Administrative Services, Distribution Energy Solutions & Regulated Renewables Development
Level 22		2/7/2023	5/12/2023	Enterprise Tech & Security
Level 23		5/11/2023	5/19/2023	Destination Floor with Labs
Level 24		6/23/2023	-	TBD
Level 25		5/17/2023	-	TBD
Level 26		5/17/2023	5/19/2023	Enterprise Tech & Security
Level 27		5/17/2023	5/19/2023	Enterprise Tech & Security
Level 28		5/17/2023	6/16/2023	Customer Delivery, Enterprise Tech & Security
Level 29		6/23/2023	6/16/2023	Customer Delivery
Level 30		6/23/2023	6/16/2023	Customer Delivery
Level 31		6/23/2023	8/4/2023	Customer Services, Pricing & Customer Solutions
Level 32		6/23/2023	8/4/2023	Customer Services, Int Grid Strategy & Solutions
Level 33		6/23/2023	8/4/2023	Supply Chain
Level 34	11/22/2023		11/25/2023	Destination Floor with Labs, Generation & Transmission
Level 35	8/2/2023		9/15/2023	RRE, Operational Excellence Assessments
Level 36	8/2/2023		9/15/2023	EHS & CCp, Project Management & Construction
Level 37	8/15/2023		9/29/2023	Nuclear
Level 38	9/21/2023		-	TBD
Level 39	8/18/2023		9/29/2023	FERC - Generation & Transmission
Level 40	8/29/2023		9/29/2023	FERC - Generation & Transmission
Level 41	10/6/2023		10/6/2023	Aspire Floor

In-Service	Completed

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Duke Energy Carolinas, LLC
Payments by Channel
As of November 25, 2022*

Quick Exhibit 1
Docket No. E-7, Sub 1276

PAYMENT COUNT	2019	2020	2021	2022*
Residential				
Electronic	8,636,969	8,896,312	9,018,184	8,830,263
Speedpay	6,011,723	5,636,465	5,685,913	5,102,223
Mail	4,458,332	4,065,603	3,611,580	2,891,077
Walk-in Pay Agent	691,439	503,017	405,890	324,878
	19,798,463	**19,101,397**	**18,721,567**	**17,148,441**
Non-Residential				
Electronic	1,291,799	1,390,859	1,501,227	1,522,432
Speedpay	184,945	169,687	189,233	179,341
Mail	1,949,761	1,821,854	1,630,844	1,359,908
Walk-in Pay Agent	40,937	33,154	29,421	23,302
	3,467,442	**3,415,554**	**3,350,725**	**3,084,983**
Total	**23,265,905**	**22,516,951**	**22,072,292**	**20,233,424**

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Overview of Rebuttal Witnesses and Scope

Witness	Topics	Scope
(1) Kendal C. Bowman	Overview of Case & PBR Policy	• Introduction and overview of the Company's rebuttal case • Describes the public hearings on the Company's Application • Describes DEC's service quality and accomplishments • Supports Performance-Based Regulation ("PBR") • Responds to the assertion that PBR reduces risk for the Company, and that DEC's return on equity ("ROE") should therefore be reduced • Comments on Public Staff and intervenor testimony regarding DEC's capital investments • Explains that DEC intends to maximize the benefits of the Inflation Reduction Act ("IRA") and Infrastructure Investments and Jobs Act ("IIJA") • Comments on affordability initiatives taken by DEC • Provides an overview of the stakeholder engagement undertaken by DEC and settlements already reached between DEC and certain parties to this case • Describes the intersection of the rate case and Carbon Plan Integrated Resource Plan processes
(2) PBR Panel: Laura A. Bateman and Phillip O. Stillman	PBR Policy & Performance Incentive Mechanism	• Provides support for DEC's PBR Application, specifically the merits of PBR and how the adoption of a PBR framework does not reduce risk to a regulated utility • Addresses issues related to installation operation and maintenance ("O&M") expenses in the Company's MYRP • Addresses Public Staff Witness Metz's allegation that certain DEC MYRP projects lack sufficient project documentation • Addresses CUCA Witness Pollock's recommendations that MYRP projects be tied to the Company's Carbon Plan and that test year billing determinants should be updated. • Addresses DEC's Earnings Sharing Mechanism ("ESM"), decoupling mechanism, the Transmission Cost Allocation Stipulation, and NCSEA

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Witness	Topics	Scope
		Witness Kaufman's recommendation that the Company stop all recovery on 50% of its subcritical coal assets in order to maximize the amounts that can be securitized • Supports DEC's proposed Performance Incentive Mechanisms ("PIMs") and tracking metrics, and responds to the Public Staff and intervenors' critiques of DEC's PIMs proposals and addresses specific PIM proposals advanced by certain intervenors
(3) Dr. Roger A. Morin	ROE and Cost of Capital	• Supports DEC's recommended ROE • Supports DEC's recommended cost of capital • Responds to the following intervenor testimony regarding ROE and cost of capital issues: o Public Staff Witness Walters o CUCA Witness LaConte o NC Justice Center et al., Witness Ellis
(4) James M. Coyne	ROE – Technical Analysis	• Provides a more detailed, technical assessment of Public Staff ROE Witness Walters and his analytical results
(5) COVID Panel: Kendal C. Bowman, Lesley G. Quick, Melissa B. Abernathy, and Nicholas G. Speros	COVID	• The COVID Panel demonstrates that cost recovery and continued deferral are appropriate • More specifically, Witness Bowman will provide brief context for the unprecedented nature of the COVID-19 Pandemic, the role that DEC played as a provider of essential service during the Pandemic, and the steps DEC took to assist customers • Witness Bowman also provides an overview of the deferral petition the Company submitted in Deferral Docket, as well as the Commission's corresponding Deferral Order, which authorized DEP to defer specific COVID-related costs to a regulatory asset for future investigation and recovery • Witness Quick provides details regarding the Company's customer engagement, efforts to assist customers, and the effects that the Company's waiver of customer fees and the Commission-ordered moratorium on disconnections had on DEC

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Witness	Topics	Scope
		• Witness Abernathy explains the categories of costs deferred to the regulatory asset and explain the immense amount of information provided to support such categorizations • Witness Abernathy shows that the Company has taken the correct approach to identify the costs that should be recovered in this proceeding • Witness Speros will address other accounting issues related to the Pandemic
(6) Kevin A. Murray	Overall MYRP Perspective	• Provides a general explanation of DEC's wholistic and comprehensive approach to MYRP project planning and execution • Discusses the Enterprise-wide Project Management Center of Excellence • Explains that the MYRP does not present a fundamentally different set of project execution challenges as compared to historic capital projects successfully completed by DEC • Supports and explains that the Company's inclusion of contingency in costs estimates is standard and accepted industry practice in cost estimation • Responds to the Public Staff's recommended disallowances based on insufficient MYRP project documentation • Responds to Public Staff Witness Lucas's recommended disallowances for the Lincoln Combustion Turbine Unit 17
(7) Daniel J. Maley	Transmission MYRP	• Addresses the overall project documentation complaints of Public Staff Witness Metz • Rebuts the testimony by Public Staff Witness T. Williamson regarding his Transmission production and inspections budget reduction recommendations, but agrees with his recommended reduction of the Company's herbicide budget, and also note capital work that was not included in the MYRP, as well as projects that DEC added in the May 2023 Supplemental Update • Explains DEC's process for selecting Transmission projects for inclusion in the MYRP and highlights – at a high level – the unprecedented amount of information that the Company provided in support of its proposed Transmission MYRP investments, meeting and exceeding statutory requirements as well as those of Commission Rule R1-17B

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Witness	Topics	Scope
		• Addresses the testimony of Public Staff Witness Chiles challenging the need for certain Transmission MYRP projects, and NC WARN Witnesses Powers' and Konidena's assessment of the cost and locations of various transmission line projects. • Describes the methodologies and procedures that DEC used to develop contingency estimates for Transmission projects and questions the methodologies used by Public Staff Witness Metz to reduce the Company's project contingency estimates by 50%. • Responds to Public Staff testimony questioning DEC's ability to execute its selected Transmission MYRP projects on schedule and with sufficient staffing • Discusses Transmission Policy recommendations raised by intervenor Witnesses Burgess and Goggin and explains why they are unnecessary
(8) Brent C. Guyton	Distribution MYRP and Distribution Base Period	• Responds to Public Staff project documentation and discovery critiques • Addresses Public Staff testimony recommendations for various Base Case Distribution Plan disallowances • Addresses Vegetation Management challenges and recommended reporting requirements raised by Public Staff Witness Williamson • Describes the processes DEC used to select certain Distribution projects for inclusion in the MYRP and rebuts the Public Staff and other intervenors who challenge the need for certain projects • Provides specific, data-driven examples as to why DEC's MYRP distribution projects are appropriate for inclusion in the MYRP • Describes the methodologies and procedures that DEC used to develop cost and contingency estimates for Distribution projects, questions estimate adjustments proposed by Public Staff Witness Thomas, and questions the methodologies used by Public Staff Witness Metz to recommend a reduction of the Company's project contingency estimates by 50% • Responds to Public Staff testimony questioning DEC's ability to execute its selected Distribution MYRP projects on schedule

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Witness	Topics	Scope
(9) Steven Capps	Nuclear MYRP and Nuclear Base Period	• Details the volume of nuclear-related discovery received by DEC and DEC's responses to such discovery • Responds to Public Staff Witness Metz's recommended removal nuclear MYRP projects based on alleged lack of project documentation • Responds to Public Staff Witness Metz's recommendations related to M&S Inventory end-of-life reserve salvage value

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Witness	Topics	Scope
(10) Bryan P. Walsh	RRE Base Period and RRE MYRP	• Details the volume of RRE-related discovery received by DEC and DEC's responses to such discovery • Responds to Public Staff Witness Michna's recommended removal of steam projects from MRYP based on alleged lack of project documentation • Responds to Public Staff Witness Thomas' recommended removal of hydro projects from the MYRP based on alleged lack of project documentation • Responds to Public Staff Witness Thomas' recommended removal of Mountain Island seismic dam project from MYRP based on timing and cost support • Responds to Public Staff Witness Thomas' adjustments to certain hydro MYRP projects • Responds to Public Staff Witness Thomas' proposed reduction to the Company's MYRP revenue requirement to account for asserted hydro project O&M savings • Responds to Public Staff Witness Metz's recommended removal of natural gas projects from the MYRP based on alleged lack of project documentation • Responds to Public Staff Witness Metz's recommended removal of Clemson Hydrogen project from MYRP based on lack of support • Responds to Public Staff Witness Michna's testimony regarding the Company's coal inventory • Responds to Public Staff Witness Michna's proposed adjustment to test year non-fuel O&M expense for the Marshall station • Responds to Public Staff Witness Lucas' testimony regarding the Lincoln pipeline • Responds to Public Staff Witness Metz's recommendations regarding the reliability assurance O&M pro forma • Responds to Public Staff Witness Metz's testimony regarding the Company's fossil fleet operations and performance

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Witness	Topics	Scope
(11) Justin C. LaRoche	Solar MYRP	• Responds to Public Staff Witness Jeff Thomas' recommendation to reduce the in-service costs, associated network upgrade costs, and annual O&M cost costs of the 2026 Solar Investment Project, which DEC agrees with
(12) Battery Energy Storage Panel: Laurel M. Meeks and Evan W. Shearer	Storage MYRP	• Responds to the Public Staff's recommended removal of the Farr's Bridge, Lowgap and Nebo microgrids from the MYRP • Rebuts the Public Staff's proposed changes to the cost allocation methodology for the microgrid projects • Addresses the Public Staff's concern about meeting Carbon Plan objectives through microgrids • Addresses Public Staff's recommendation that DEC consider adding additional storage at the Allen coal plant
(13) Donna T. Council	Duke Energy Plaza Inclusion in DEP Rent Expense	• Responds to Public Staff Witness Metz's testimony recommending disallowance of portions of the capital cost of the Duke Energy Plaza building and: o Explains the reasons Duke Energy undertook an evaluation of its real estate portfolio beginning in 2014 and the alternatives Duke Energy considered as part of its real estate strategy over the course of the project development o Explains why Public Staff Witness Metz's renovation alternative was not a viable option and why the Company chose to build the Duke Energy Plaza
(14) Jacob J. Stewart	Compensation	• Responds to the incentive compensation disallowances recommended by Public Staff Witnesses Zhang and Boswell • Responds to Public Staff's recommendations regarding executive benefits and costs

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Witness	Topics	Scope
(15) Melissa B. Abernathy	ESM, Decoupling, and MYRP	• Responds to the Public Staff, as well as AGO Witness Palmer and CUCA Witness Pollock, regarding DEC's PBR Application, specifically their recommendations related to: o DEC's proposed Decoupling Mechanism o DEC's proposed ESM o The inclusion of certain MYRP projects o Company's request to defer impacts associated with the IRA o The Company's request to defer impacts associated with the IIJA
(16) Quynh Bowman	Accounting and Rates	• Responds to accounting and ratemaking adjustments made by Public Staff
(17) Rate Design Panel: Jonathan L. Byrd and Morgan Beveridge	Rate Policy and Rate Design	• Addresses reduction in subsidies as discussed in the testimony of CIGFUR III Witness Brian Collins, CUCA Witnesses Pollock and Lyons, and Public Staff Witness Williamson • Addresses Time-of-Use ("TOU") periods as discussed in the testimony of AGO Palmer and CUCA Witness Pollock • Addresses non-residential rate designs as discussed in the testimony of Public Staff Witnesses Nader and Williamson, AGO Witness Palmer, Kroger Co. and Harris Teeter LLC Witness Bieber, Commercial Group Witness Chriss, CUCA Witnesses Pollock and Lyons, and CIGFUR III Witness Collins • Addresses the residential TOU rate design as discussed in the testimony of AGO Witness Palmer • Addresses communication of the changes to lighting services, rate schedules, and service regulations as discussed in the testimony of Public Staff Witness Williamson • Responds to the testimony of Public Staff Witnesses Nader and Williamson, AGO Witness Palmer, and NC WARN Witnesses Powers and Konidena regarding riders

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Witness	Topics	Scope
		• Discusses the inclusion of incremental electrical vehicle revenues in an adjustment to the decoupling deferral calculation as discussed in the testimony of Public Staff Witness Nader and AGO Witness Palmer • Discusses the feasibility of a multi-site aggregate commercial rate and pilot program, as discussed in the testimony of Harris Teeter Witness Bieber • Discusses the ability of the Public Staff to provide a customer class revenue requirement apportionment as raised in the testimony of Public Staff Witness Williamson
(18) John J. Spanos	Depreciation	• Responds on behalf of the Company to depreciation-related issues filed by Public Staff Witness Roxie McCullar, Public Staff Witness Lucas, and NCSEA Witness Kaufman
(19) Nicholas G. Speros	Accounting	• Addresses Public Staff's proposed adjustments relating to the Company's accounting methods relating to: o Contributions in Aid of Construction ("CIAC"), o lobbying expenses o DEC's lead-lag study o Chamber of Commerce expenses o the South Church switchgear and generator replacement o workstations o Mount Holly Technology and Innovation Center • Addresses CIGFUR Witness Collin's recommendations regarding vegetation management
(20) Lesley G. Quick	Customer Service Programs	• Responds to the Joint Testimony of Public Staff Witnesses Fenge Zhang and Michelle Boswell and the recommendation to remove the adjustment of nonresidential credit card fees associated with credit, debit, and Automated Clearing House payment expenses
(21) Karl W. Newlin	Capital Structure and Credit Quality	• Responds to a number of intervenor witness proposals regarding capital structure, specifically the following: o Public Staff Witness Walters

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Witness	Topics	Scope
		○ CUCA Witness LaConte ○ NC Justice Center et al., Witness Ellis • Responds to the ROE recommendations of the above witnesses with respect to the Company's need to secure capital
(22) John R. Panizza	Tax	• Explains that no intervenor took issue with DEC's description of IRA tax credits, and that Public Staff supports the IRA deferral request in light of the uncertainties attendant upon those credits • Responds to Public Staff Witness Metz's and Public Staff Witness Lucas's testimony implicating tax issues
(23) Bryan L. Sykes	Fuel	• Responds to Public Staff Witness Lucas's testimony regarding the inclusion of voltage differential in fuel rates • Responds to the Public Staff's recommended theoretical fuel rates
(24) Cynthia Klein	IIJA	• Describes DEC's approach to identifying and pursuing federal grants and loans that may be available under the IIJA • Describes the rigorous prioritization methodology DEC has employed to determine which federal funding opportunities it should pursue under the IIJA • Describes the actions DEC has taken since the IIJA was signed into law to keep the Commission and the Public Staff apprised of the Company's efforts to identify and apply for IIJA programs that could potentially offset future investments • Provides information on DEC's eligibility for IIJA funding and pursuit of federal funds for certain of the MYRP hydroelectric projects that were identified in the direct testimony of Public Staff witness Thomas • Responds to Public Staff Witness Thomas's recommendation that the costs of MRYP hydroelectric projects should be adjusted to reflect the potential award of with IIJA incentives • Responds to Public Staff Witness Nader regarding the treatment of potential IIJA funding awards in the MYRP
(25) Jeffrey Kopp	Decommissioning	• Responds to Public Staff's recommendations to adjust certain costs related to the Company's Decommissioning Study, specifically Public Staff Witness Lucas's recommendations to:

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Witness	Topics	Scope
		○ Remove asbestos removal cost for the Bad Creek Hydroelectric Plant and the Bridgewater Hydroelectric Plant as well as his recommendation to reduce the cost for asbestos removal at the 99 Islands Hydroelectric Plant ○ Set project indirect adders at 5% rather than the 10% recommended in the Decommissioning Study ○ Adopt a 10% contingency adder rather than the Decommissioning Study's 20% contingency adder.